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ELECTRIC POWER WHEELING AND DEALING:

Technological Considerations for Increasing Competition

VOLUME II -- CONTRACTOR DOCUMENTS

Part A

1. Transmission Line Certification and Siting Procedures amd Energy Planning Processes
2. Electric Utility Generation and Transmission Planning and Coordination
3. Summary of Responses of the Regional Reliability Councils to the National Governors' Association Survey on Electric Transmission Coordination and Planning
4. Planning and Coordination of Utility Bulk Power Supplies and Transmission Capacity

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J957-58

DRAFT

TRANSMISSION LINE CERTIFICATION AND SITING PROCEDURES AND ENERGY PLANNING PROCESSES:

SUMMARY OF STATE GOVERNMENT RESPONSES TO A SURVEY BY THE NATIONAL GOVERNORS' ASSOCIATION TASK FORCE ON ELECTRICITY TRANSMISSION

JULY 1988

Note: This document was prepared by staff members of the Public Utilities Commission of the State of Ohio and of the West Virginia Public Service Commission under contract with the U.S. Congress, Office of Technology Assessment, Washington, D.C. This document was prepared for reference purposes and is being distributed for review and comment only and should not otherwise be reproduced, referenced or quoted. The conclusions expressed in this paper are those of the authors and do not necessarily reflect the views of the Office of Technology Assessment, the Public Utilities Commission of Ohio, the West Virginia Public Service Commission, or the National Governors' Association Task Force on Electricity Transmission. This document has not been reviewed or approved by the Technology Assessment Board.

SURVEY RESULTS OF STATE GOVERNMENT TRANSMISSION LINE CERTIFICATION AND SITING PROCEDURES and ENERGY PLANNING PROCESSES

INTRODUCTION

This report, sponsored by the Office of Technology Assessment (OTA), presents the results of a survey concerning state transmission line certification and siting procedures, and state energy planning processes. The original survey was conducted by the National Governors' Association Task Force on Electricity Transmission in the fall of 1986.* Responses to the original survey were provided by forty-five states and the District of Columbia. Additional survey forms were sent to the non-respondents and follow-up contacts resulted in a data base which contains responses from all of the states except Colorado and Connecticut.

Section I summarizes the state transmission line certification and siting procedures. Certification refers generally to approval of need and siting refers to approval of location. This section of the survey contains information on the following areas:

1) organizational characteristics of the responsible agency(s);
2) approval criteria;
3) factors considered in the process such as intended use of line, alternative routes and eminent domain;
4) the treatment of interstate projects;
5) filing procedures, the public hearing process and their time frame; and
6) factors which expedite or hinder the process.

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* The information collected was referenced in the NGA Task Force Report Moving Power; but due to time constraints it was not fully documented or analyzed.

Section II concerns state energy planning processes and contains information on the following areas:

1) does the state perform independent forecasts?;
2) information contained and frequency;
3) the use of state forecasts and plans;
4) forecast filings by utilities, holding companies and power pools;
5) state evaluation of forecast filings; and
6) state participation in extra-state planning processes.

The results of this project are presented in the following Section I and Section II of this report.

SECTION I
STATE CERTIFICATION AND SITING PROCESSES

This section reports the survey results concerning processes for the state certification and siting of new electric transmission lines. These results are collected in three Tables:

Table I.1 - Structure of State Regulatory Process;
Table I.2 - Regulatory Process for Interstate Facilities; and
Table I.3 - State Regulatory Experience

In addition to these tables, the responses are summarized in a Summary Report for each table. Further, the following text contains summary information about eminent domain variations among the states.

Table I.1 and the associated Summary Report describe the structure of state regulatory processes. Thirty-six of the responding states require certification and thirty-seven states require siting approval. In eight states neither certification nor siting approval is required. Four of the states requiring certification do not require siting approval and the siting approval requirements in Delaware, Georgia, and New Jersey are very limited. Five of the states requiring siting approval do not require certification. (Note that throughout this survey Colorado and Connecticut are recorded as no responses.)

Of thirty-six states requiring certification, the Public Utility Commission (PUC) or its equivalent is the responsible lead agency in twenty-seven, and the PUC shares that responsibility in three additional states. The PUC is also the lead agency regarding siting approval in twenty-one states and shares that responsibility in four states. In nineteen states the lead agency for both certification and siting approval is the PUC. Reference to the Summary Report for Table I.1 shows that the percent of applicable responses answering "yes" to the following are:

1. Non-State Agencies Formally Involved?	44%
2. Certification and Siting Approved Jointly?	64%
3. Certification Needed to Upgrade Existing Line?	51%
4. Intended Use of Line Statement Required?	97%
5. Alternate Routes Study Required?	74%

In twenty of thirty-six states requiring certification one filing is required and in fifteen of thirty-seven states requiring siting approval only one filing is required. Fourteen states permit the joint filing of the certification and siting approval application. Only one state requires two or more certification filings and seven states require two or more siting filings. The majority of states require public hearings and the majority provide for certification and siting in a joint hearing. In virtually every instance where public hearings are required or held, all interested parties are allowed to participate.

States were asked to note the factors promoting or hindering timely consideration of applications. The most frequently cited factors promoting timely consideration are responsibility by a single agency and the existence of statutory time frames. The absence of these factors are cited as hindrances to a timely process, but the most frequently cited factor appears to be related to public hearings and other procedures which permit participants to complicate issues, provide aggressive opposition, and intentionally delay the approval process (See Table I.1, page 2).

Table I.2 and its associated Summary Report concern the regulatory process for interstate facilities. First, it can be seen that the approval criteria used for certification, siting, and eminent domain do not vary in the vast majority of states when the transmission line is interstate. However, 88 percent of the states do not consider the need for interstate power as part of the approval criteria. When the new transmission line is for service in a utility's own area the most frequently cited criteria are need for power, environmental concerns, and the "public interest." For transmission lines to be used substantially for inter-utility sales, the most frequently required criteria for approval are need for power, system reliability, and the "public interest." It is interesting to note that many of the states which cite "public interest" as a factor for approval did not explicitly define this term.

Table I.3 and its associated Summary Report concerns state regulatory experiences with recent and past certification and siting requests. Information on typical and possible days from initial filing to final approval is shown for the certification process, siting process, and where this process is joint. Also information on current and past projects is shown. The Summary Report also displays the average (AVG), the standard deviation (STD), and the total responses (SUM) where applicable.

The summary information regarding typical time frame indicates that, on average, certification and/or siting takes from four to eleven months. However, the high standard deviations indicate a wide range of responses. The average typical time frame in each case is well within the stated average range of possible time frames.

Seventy-three projects have been approved in the last year and there are a total of eighty-four requests pending approval. The majority of projects approved within the last five years have been completed. Finally, twenty-four of thirty-three applicable responses indicate requests for certification or siting for interstate lines.

The remaining information gathered from this survey pertains to eminent domain. In thirty-one of thirty-six responses, eminent domain is granted for individual projects rather than classes of projects. In these states which grant eminent domain for individual projects, only eleven states do so in conjunction with the siting approval process. Reference to the Summary Report for Table I.2 indicates no instance of the approval criteria for eminent domain being different when the project involves an interstate line. The most frequent method by which a utility receives eminent domain for a project is from the state agency responsible for certification and/or siting approval. Generally, the specific requirements for eminent domain vary a great deal with individual state statutes.

In conclusion, the certification and siting approval process is heavily dominated by the individual state's Public Utility Commission, or its equivalent. Approximately one-fourth of the states do not require certification and/or siting approval at the state level. The filing and hearing requirements appear to be minimal, although the hearing process appears to be the source of delays as viewed by the respondents in many cases. Finally, these processes can take from a few months to a year on average, but for an individual state may range from months to years.

SECTION II
STATE PLANNING PROCESSES

This section reports the survey results concerning processes the state provides for the forecasting of and planning for electricity supply and demand within the state, and in neighboring jurisdictions. The results are collected in three tables:

Table II.1 - State Planning and Forecasting Activities;
Table II.2 - Utility Planning and Forecasting Activities; and
Table II.3 - State Oversight of Utility Forecasts

In addition to these tables, the responses are summarized in a Summary Report for each table.

Table II.1 and the associated Summary Report describe state planning and forecasting activities. The data compiled in this table indicate that a large percentage of states do not conduct independent forecasts, and those that do often underutilize them. Of those states responding, one would thirty have agencies responsible for the preparation of such plans and forecasts, while sixteen do not. Additionally, Michigan does so only for rate case proceedings. The Public Utility Commission (PUC) or its equivalent is responsible for the preparation of these plans and forecasts in eighteen of the thirty states that do perform independent plans and forecasts, and only nineteen utilize them in the certification and siting of new generating plant. Also only fifteen utilize them in the certification and siting of new transmission plant. If these states do not make use of plans and forecasts prepared by the responsible agencies, this would imply a strong reliance on data compiled by outside sources in the decision making process.

Generation and transmission issues are increasingly viewed on a regional or national basis and are not merely a statewide issue. However, many states indicate either no, or very limited consideration of regional supply and demand in their planning process. Twenty-four of the forty-nine respondents are not participating in any broad-based planning process with outside groups such as other states, regional planning authorities, or utilities. These states tend to have a much narrower view of key transmission and generation issues than those who participate in a more regionally based planning process.

Table II.2 and the associated Summary Report describe utility planning and forecasting activities and the extent to which the utility plans are required by State regulatory agencies for consideration in certification, siting or rate cases. Plans and forecasts conducted by the utilities are much more prevalent in case proceedings than plans prepared by state agencies. Thirty-two states require utilities to submit plans for the certification and siting of generation facilities. Twenty-five require them for the certification and siting of new transmission facilities. As shown in the Summary Report on Table II.2, of those states responding, the percentage of utility plans include analysis of the following:

Interstate Generating Capacity	83%
Intrastate Sales/Purchases	97%
Interstate Sales/Purchases	100%
Need for Transmission Facilities	86%
Least Cost Power Alternatives	83%
Transmission of Least Cost Power	66%
Load Management	3%
Conservation	3%

Table II.3 and the associated Summary Report describe state oversight of utility forecasts. Thirty-four states have access to power pool and/or holding company plans or forecasts regarding the need for new transmission facilities. The PUC is most often the receiving agency for capacity and investment plans and forecasts, and also most often has the responsibility to evaluate them.

Section II of the survey conveys a reliance on utility plans and forecasts in the decision making process to a much greater extent than independent plans and forecasts performed by the responsible state agency. State plans appear to be underutilized, especially during rate case one would proceedings. States also have a very narrow scope in dealing with the regional planning process, with almost one-half not participating in any extra-state planning process in any form. This would tend to produce a fragmented and otherwise limited view of the needs and demands on electric service in the country.

SUMMARY REPORT

TABLE I.1 (page 1)
STRUCTURE OF STATE REGULATORY PROCESS
CERTIFICATION AND SITING NEW TRANSMISSION LINE

STATE CERTIFICATION AUTHORITIES	
PUC	30
Siting Board	5
Land or Planning	4
Not Required	13
No Response	2

LEAD AGENCY FOR CERTIFICATION	
PUC	27
Other(non-PUC)	5
Shared	3
Not Applicable	13
No Response	3

AUTHORITY TO OVERRIDE OTHER AGENCIES?	
Yes	16
No	11
Not Applicable	21
No Response	3

STATE SITING AUTHORITIES	
PUC	26
Siting Board	8
Energy Office	1
Land or Planning	12
Environmental	5
Not Required	12
No Response	2

LEAD AGENCY FOR SITING	
PUC	21
Other(non-PUC)	8
Shared	4
Not Applicable	13
No Response	5

AUTHORITY TO OVERRIDE OTHER AGENCIES?	
Yes	17
No	9
Not Applicable	19
No Response	6

AGENCY WITH FINAL AUTHORITY FOR TOTAL PROJECT?	
PUC	18
Other(non-PUC)	6
Shared	3
Not Applicable	16
No Response	8

NON-STATE AGENCIES FORMALLY INVOLVED? CONSULTED?	
Involved	17
Consulted	18
None	4
No Response	12

CERTIFICATION AND SITING APPROVED JOINTLY?	
Yes	21
No	11
Sometimes	2
Not Applicable	14
No Response	3

SUMMARY REPORT

TABLE I.1 (page 2)
STRUCTURE OF STATE REGULATORY PROCESS
CERTIFICATION AND SITING NEW TRANSMISSION LINE

ANOTHER FORM OF APPROVAL REQUIRED?	
Yes	8
No	28
Sometimes	1
Not Applicable	10
No Response	4

CERTIFICATION NEEDED TO UPGRADE EXISTING LINE?	
Yes	14
No	13
Sometimes	7
Not Applicable	13
No Response	4

INTENDED USE OF LINE STATEMENT REQUIRED?	
Yes	36
No	1
Not Applicable	10
No Response	4

NUMBER OF SEPARATE FILINGS REQUIRED?	
Certification =1	20
Siting =1	15
Certification =2+	1
Siting =2+	7
Joint Filing	14
Not Applicable	8
No Response	2

PUBLIC HEARINGS REQUIRED?	
Certification =yes	9
Siting =yes	10
Joint Hearing	16
None	1
Discretionary	10
Not Applicable	8
No Response	3

HEARINGS PARTICIPATION?	
All Interested Parties	37
All Affected Parties	1
Public; Officials	1
Not Applicable	10
No Response	4

ALTERNATE ROUTES STUDY REQUIRED?	
Yes	27
No	9
Sometimes	1
Not Applicable	10
No Response	4

SUMMARY REPORT

TABLE I.1 (page 3)
STRUCTURE OF STATE REGULATORY PROCESS
CERTIFICATION AND SITING NEW TRANSMISSION LINE

MOST IMPORTANT FACTOR(S) PROMOTING TIMELY CONSIDERATION?	
Statutory Time Frame	9
Single Agency	14
Ease of Process	4
Discretionary Hearings	1
Joint Review	1
Information Requirements	3
Formal Planning Process	2
Limited Siting Authority	2
Not Applicable	10
No Response	5

MOST IMPORTANT FACTOR(S) HINDERING TIMELY CONSIDERATION?	
Reviews/Opposition/Issues	9
Environmental Constraints	2
Incomplete Information	5
Lack of Resources	4
Duplication of Effort	2
Cumbersome Process	3
Lack of Deadlines	2
Court Involvement	2
Other Agencies Involved	1
None	1
Not Applicable	10
No Response	7

METHODS USED ROUTINELY TO EXPEDITE PROCESS?	
Joint consideration of all required certificates	20
Single agency	19
Joint filings and/or hearings	9
Joint consideration of unrelated trans. projects	6
Joint consideration of trans. and gen. projects	9
Need for power	2
Pre-approval of rights-of-way	1
Informal discussions with utilities	19
Informal discussions prior to application	8
Coordination with local authorities	14
Coordination with other states/regional/federal	6
None	3
Not Applicable	10
No Response	3

TABLE I.2 (page 1)
REGULATORY PROCESS FOR INTERSTATE FACILITIES
CERTIFICATION AND SITING TRANSMISSION LINES

APPROVAL CRITERIA ---NEW TRANSMISSION LINE FOR UTILITY'S OWN SERVICE TERRITORY?	
Need For Power	31
State Environmental Regulations	27
Public Environmental Concerns	29
State Land Use Requirements	22
Local Land Use and Zoning	26
"Public Interest"	27
System Reliability	6
Economics/Cost	5
Available Alternatives	4
Safety Considerations	3
Long Range Planning	2
Size of Line	3
Other Factors	6
Not Applicable	10
No Response	4

APPROVAL CRITERIA FOR CERTIFICATION VARYS WHEN LINE IS INTERSTATE?	
Yes	2
No	29
Sometimes	3
Not Applicable	13
No Response	3
Unknown	1

APPROVAL CRITERIA FOR SITING VARYS WHEN LINE IS INTERSTATE?	
Yes	1
No	32
Sometimes	1
Not Applicable	11
No Response	6

APPROVAL CRITERIA FOR EMINENT DOMAIN VARYS WHEN LINE IS INTERSTATE?	
Yes	0
No	29
Unknown	1
Not Applicable	13
No Response	7

TABLE I.2 (page 2)
REGULATORY PROCESS FOR INTERSTATE FACILITIES CERTIFICATION AND SITING TRANSMISSION LINES

ADDITIONAL APPROVAL CRITERIA --- NEW INTER-UTILITY TRANSMISSION LINES FOR SALES --- REQUIRED	
Distribution Power Obligations	17
Utility Service Reliability	20
Need For Power	20
Opportunity To Sell Existing Power	15
Opportunity To Sell Future Power	15
Opportunity To Profit From Wheeling	13
Access By Public Utilities	10
Access By Any Other Utility	8
"Public Interest"	20
Economics/Cost	2
Long Range Planning	2
System Reliability	1
Safety Considerations	1
Other Factors	5
None	3
Not Applicable	12
No Response	4

ADDITIONAL APPROVAL CRITERIA --- NEW INTER-UTILITY TRANSMISSION LINES FOR SALES --- CONSIDERED	
Distribution Power Obligations	9
Utility Service Reliability	8
Need For Power	7
Opportunity To Sell Existing Power	10
Opportunity To Sell Future Power	10
Opportunity To Profit From Wheeling	11
Access By Public Utilities	8
Access By Any Other Utility	9
"Public Interest"	7
All Other Relevant Factors	4
Other Factors	1
None	2
Not Applicable	11
No Response	18

APPROVAL CRITERIA CONSIDERS INTERSTATE NEED FOR POWER IN CASE OF MULTI-STATE UTILITY ?	
Yes	4
No	29
Not Applicable	12
No Response	6

"PUBLIC INTEREST" STANDARD FOR INTERSTATE LINES?	
No Difference	24
More Stringent	1
More Difficult In Practice	3
Not Applicable	19
No Response	4

SUMMARY REPORT

TABLE I.3 (page 1)
STATE REGULATORY EXPERIENCE
CERTIFICATION AND SITING TRANSMISSION LINES

TYPICAL DAYS FROM INITIAL FILING TO FINAL APPROVAL :

	CERTIFICATION?		SITING?		JOINT?	
	MIN.	MAX.	MIN.	MAX.	MIN.	MAX.
AVG	137	268	132	319	120	336
STD	97	142	59	110	65	211

HOW MANY PROJECTS HAVE BEEN APPROVED IN YOUR STATE :

	WITHIN THE LAST YEAR?	WITHIN THE LAST 5 YEARS?	WITHIN THE LAST 10 YEARS?	MORE THAN 10 YEARS AGO?
SUM	73	317	422	331
AVG	2	10	16	16
STD	4	14	24	42

HOW MANY REQUESTS ARE PENDING APPROVAL FOR:

	CERTIFICATION ONLY?	SITING ONLY?	BOTH?	OTHER?
SUM	10	8	49	17
AVG	0	0	2	1
STD	1	1	5	2

SUMMARY REPORT

TABLE I.3 (page 2)
STATE REGULATORY EXPERIENCE
CERTIFICATION AND SITING TRANSMISSION LINES

POSSIBLE TIMEFRAME FOR APPROVAL (SHORTEST-LONGEST) :

	CERTIFICATION?		SITING?		JOINT?	
	MIN.	MAX.	MIN.	MAX.	MIN.	MAX.
AVG	82	480	120	545	154	495
STD	76	506	71	488	165	390

HOW MANY PROJECTS APPROVED WITHIN LAST 5 YEARS ARE NOW:

	LAND ACQUISITION PHASE ?	UNDER CONSTRUCTION?	COMPLETED?	CANCELLED/ MOTHBALLED?
SUM	17	71	172	11
AVG	1	3	7	0
STD	2	4	13	1

REQUESTS FOR CERTIFICATION OR SITING OF INTERSTATE LINE WITHIN LAST 5 YEARS?	
None	11
Yes, one other state	15
Yes, more than one other	9
Not Applicable	11
No Response	5

SUMMARY REPORT

TABLE II.1 (page 1)
INDEPENDENT STATE PLANNING AND FORECASTING ACTIVITIES

INDEPENDENT FORECASTING AGENCIES	
PUC	18
Energy Office	12
Siting Board	1
Other	11
None	16
No Response	2

FREQUENCY OF FORECASTS ?	
< Every 2 Years	16
Every 2 to 5 Years	10
> Every 5 Years	0
With Certification	3
Rate Case Only	1
Not Applicable	17
No Response	4

TIMEFRAME(S) OF FORECASTS ?	
5 Years	3
10 Years	10
15 Years	8
20 Years	14
25 Years	1
Not Applicable	17
No Response	4

ELEMENTS INCLUDED IN STATE PLAN ?	
Intrastate Supply and Demand	25
Interstate Supply and Demand	12
Other Sources of Power	17
Need/Source of Generating Capacity	20
Transmission Capacity Needs	13
Intrastate Electricity Supply	2
Other Factors	2
Not Applicable	19
No Response	5

PLANS INCLUDE TRANSMISSION CAPACITY REGARDING ?	
Anticipated Supply and Demand	12
Existing Supply and Demand	2
Both Anticipated and Existing	2
Not Applicable	22
No Response	13

TABLE II.1 (page 2)
INDEPENDENT STATE PLANNING AND FORECASTING ACTIVITIES

PLANS USED IN CERTIFICATION AND SITING OF NEW GENERATING PLANT ?	
Yes	19
No	0
Not Applicable	20
No Response	12

RESULTS USED IN CERTIFICATION AND SITING OF NEW TRANSMISSION PLANT ?	
Yes	15
No	0
Not Applicable	19
No Response	17

RESULTS USED IN RATEMAKING PROCESS ?	
Yes	11
No	0
Not Applicable	19
No Response	21

STATE INVOLVED IN EXTRA-STATE PLANNING PROCESS WITH ?	
No	24
Yes, Other States	8
Yes, Regional	8
Yes, Utilities etc.	11
Not Applicable	0
No Response	7

TABLE II.2
UTILITY PLANNING AND FORECASTING ACTIVITIES

PLANS REQUIRED FOR CERTIFICATION AND SITING OF GENERATION FACILITIES?	
Yes	32
No	5
No Response	14

PLAN REQUIRED FOR GENERATION RELATED RATE CASE?	
Yes	27
No	10
No Response	14

PLAN REQUIRED FOR CERTIFICATION AND SITING OF TRANS. FACILITIES?	
Yes	25
No	10
Siting Only	1
No Response	15

PLAN REQUIRED FOR TRANSMISSION RELATED RATE CASE?	
Yes	17
No	16
No Response	18

UTILITY PLANS INCLUDE ANALYSIS OF ?	
Interstate Generating Capacity	29
Intrastate Sales/Purchases	34
Interstate Sales/Purchases	35
Need For Transmission Facilities	30
Least Cost Power Alternatives	29
Transmission of Least Cost Power	23
Load Management	1
Conservation	1
No Response	17

PLANS SUBMITTED BY POWER POOL/ HOLDING CO. FOR WHAT ENTITY ?	
Entire System	3
Individual Utility	10
Both	12
Not Applicable	7
No Response	17

TABLE II.3
STATE OVERSIGHT OF UTILITY FORECASTS

ACCESS TO POWER POOL/HOLDING CO. FORECASTS OF TRANSMISSION NEEDS?	
Yes	34
No	7
Not Applicable	1
No Response	7

ACCESS TO POWER POOL/HOLDING CO. FORECASTS OF NEEDS IN STATE?	
Yes	22
No	4
Power Pool Only	1
Holding Co. Only	1
Not Applicable	5
No Response	18

RECIEVING AGENCIES FOR CAPACITY/ INVESTMENT PLANS AND FORECASTS?	
PUC	43
Energy Office	6
Other	6
Not Applicable	1
No Response	6

DO THESE AGENCIES EVALUATE UTILITY PLANS?	
Yes	39
No	5
For New Gen. Only	1
Not Applicable	0
No Response	6

TABLE ORGANIZATION ABBREVIATIONS

BEP	Board of Environmental Protection
BLM	U.S. Bureau of Land Management
BNRC	Board of Natural Resources and Conservation
BPU	Board of Public Utilities
CC	Corporation Commission
DECA	Dept. of Economic and Community Affairs
DEED	Dept. of Energy and Economic Development
DEP	Dept. of Environmental Protection
DEPC	Division of Energy Planning and Conservation
DER	Dept. of Environmental Regulation
DNR	Dept. of Natural Resources
DOC	Dept. of Commerce
DOE	Dept. of Energy
DOT	Dept. of Transportation
DPCE	Dept. of Pollution Control and Ecology
DPL	Dept. of Public Lands
DPS	Dept. of Public Service
EC	Economic Commission
EFSB	Energy Facilities Siting Board
EFSEC	Energy Facilities Site Evaluation Council
EQB	Environmental Quality Board
ETB	Energy and Transportation Board
FEPCG	Fla. Electric Power Coordinating Group
GOCS	Gov.'s Office of Community Services
ISA	Industrial Siting Administration
LURC	Land Use Regulatory Commission
PRB	Power Review Board
PSB	Public Service Board
PSC	Public Service Commission
PUC	Public Utilities Commission
SCC	State Corporation Commission
TVA	Tennessee Valley Authority
UTC	Utilities and Transportation Commission

TABLE SYMBOLS AND ABBREVIATIONS

NA	Respondent stated question was not applicable.
?	Respondent stated answer was unknown.
*	Question not applicable based on a previous answer.
AVG	Average response in days
STD	Standard deviation of responses in days
SUM	Total of responses in days

SUMMARY REPORT

TABLE 1.1 STRUCTURE OF STATE REGULATORY PROCESS
CERTIFICATION AND SITING NEW TRANSMISSION LINE

STATE CERTIFICATION AUTHORITIES	
PUC	30
Siting Board	5
Land or Planning	4
Not Required	13
No Response	2

LEAD AGENCY FOR CERTIFICATION	
PUC	27
Other(non-PUC)	5
Shared	3
Not Applicable	13
No Response	3

AUTHORITY TO OVERRIDE OTHER AGENCIES?	
Yes	16
No	11
Not Applicable	21
No Response	3

STATE SITING AUTHORITIES	
PUC	26
Siting Board	8
Energy Office	1
Land or Planning	12
Environmental	5
Not Required	12
no response	2

LEAD AGENCY FOR SITING	
PUC	21
Other(non-PUC)	8
Shared	4
Not Applicable	13
No Response	5

AUTHORITY TO OVERRIDE OTHER AGENCIES?	
Yes	17
No	9
Not Applicable	19
No Response	6

AGENCY WITH FINAL AUTHORITY FOR TOTAL PROJECT?	
PUC	18
Other(non-PUC)	6
Shared	3
Not Applicable	16
No Response	8

NON-STATE AGENCIES FORMALLY INVOLVED? CONSULTED?	
Involved	17
Consulted	18
None	4
No Response	12

CERTIFICATION AND SITING APPROVED JOINTLY?	
Yes	21
No	11
Sometimes	2
Not Applicable	14
No Response	3

ANOTHER FORM OF APPROVAL REQUIRED?	
Yes	8
No	28
Sometimes	1
Not Applicable	10
No Response	4

CERTIFICATION NEEDED TO UPGRADE EXISTING LINE?	
Yes	14
No	13
Sometimes	7
Not Applicable	13
No Response	4

INTENDED USE OF LINE STATEMENT REQUIRED?	
Yes	36
No	1
Not Applicable	10
No Response	4

ALTERNATE ROUTES STUDY REQUIRED?	
Yes	27
No	9
Sometimes	1
Not Applicable	10
No Response	4

NUMBER OF SEPARATE FILINGS REQUIRED?	
Certification -1	20
Siting -1	15
Certification -2+	1
Siting -2+	7
Joint Filing	14
Not Applicable	8
No Response	2

PUBLIC HEARINGS REQUIRED?	
Certification -yes	9
Siting -yes	10
Joint Hearing	16
None	1
Discretionary	10
Not Applicable	8
No Response	3

HEARINGS PARTICIPATION?	
All Interested Parties	37
All Affected Parties	1
Public; Officials	1
Not Applicable	10
No Response	4

MOST IMPORTANT FACTOR(S) PROMOTING TIMELY CONSIDERATION?	
Statutory Time Frame	9
Single Agency	14
Ease of Process	4
Discretionary Hearings	1
Joint Review	1
Information Requirements	3
Formal Planning Process	2
Limited Siting Authority	2
Not Applicable	10
No Response	5

MOST IMPORTANT FACTOR(S) HINDERING TIMELY CONSIDERATION?	
Reviews/Opposition/Issues	9
Environmental Constraints	2
Incomplete Information	5
Lack of Resources	4
Duplication of Effort	2
Cumbersome Process	3
Lack of Deadlines	2
Court Involvement	2
Other Agencies Involved	1
None	1
Not Applicable	10
No Response	7

METHODS USED ROUTINELY TO EXPEDITE PROCESS?	
Joint consideration of all required certificates	20
Single agency	19
Joint filings and/or hearings	9
Joint consideration of unrelated trans. projects	6
Joint consideration of trans. and gen. projects	9
Need for power	2
Pre-approval of rights-of-way	1
Informal discussions with utilities	19
Informal discussions prior to application	8
Coordination with local authorities	14
Coordination with other states/regional/federal	6
None	3
Not Applicable	10
No Response	3

TABLE I.1 STRUCTURE OF STATE REGULATORY PROCESS
CERTIFICATION AND SITING NEW TRANSMISSION LINE

STATE	STATE CERTIFICATION AUTHORITIES	LEAD AGENCY FOR CERTIFICATION	AUTHORITY TO OVERRIDE OTHER AGENCIES?	STATE SITING AUTHORITIES	LEAD AGENCY FOR SITING	AUTHORITY TO OVERRIDE OTHER AGENCIES?	AGENCY WITH FINAL AUTHORITY FOR TOTAL PROJECT?	CERTIFICATION AND SITING COMMENTS
ALABAMA	Not Required	*	*	Not Required	*	*	*	Transmission is deemed ordinary extension of existing system.
ALASKA	Not Required	*	*	Not Required	*	*	*	Siting by local planning and zoning boards.
ARIZONA	Not Required	*	*	CC; Siting Committee	CC	yes	*	Individual transmission line approval implicit in original certification.
ARKANSAS	PSC	PSC	no	PSC; BPCE	PSC	no	PSC	
CALIFORNIA	PUC ; EC	either	yes	PUC ; EC	either	yes	either	Lead agency and final authority depends upon type of line.
COLORADO								
CONNECTICUT								
DELAWARE	Not Required	*	*	DOT (limited)			*	DOT's responsibility for siting is limited to projects on its rights-of-way.
DISTRICT OF COLUMBIA	PSC	PSC	NA	Not Required	*	*	*	PSC regulates construction generally; however, no recent experience.
FLORIDA	PSC	PSC	yes	Siting Board; DER	Siting Board	yes	Siting Board	Other affected state and local agencies also involved. PSC determines need before environmental review.
GEORGIA	Not Required	*	*	DNR (limited)			*	Dept. of Natural Resources has authority if siting involves historical/ecological significance.
HAWAII	DNR			PUC; DNR (limited)				Dept. of Land and Natural Resources if siting over conservation areas.

* Question is not applicable since certification and/or siting is not required at the state level.

TABLE I.1 STRUCTURE OF STATE REGULATORY PROCESS
CERTIFICATION AND SITING NEW TRANSMISSION LINE

STATE	STATE CERTIFICATION AUTHORITIES	LEAD AGENCY FOR CERTIFICATION	AUTHORITY TO OVERRIDE OTHER AGENCIES?	STATE SITING AUTHORITIES	LEAD AGENCY FOR SITING	AUTHORITY TO OVERRIDE OTHER AGENCIES?	AGENCY WITH FINAL AUTHORITY FOR TOTAL PROJECT?	CERTIFICATION AND SITING COMMENTS
IDAHO	PUC	PUC	yes	PUC	PUC	yes	PUC	PUC only certifies first entry of transmission line into a county; investor-owned utilities only.
ILLINOIS	ICC	ICC	yes	ICC	ICC	yes	ICC	
INDIANA	Not Required	*	*	Not Required	*	*	*	
IOWA	Utilities Div., DOC	Utilities Div.	NA	Utilities Div. City Government	Utilities Div.	NA	Utilities Div.	Siting responsibility by Utilities Division outside of cities only.
KANSAS	CC	CC	NA	CC	CC	NA	CC	CC evaluates necessity of proposed lin especially when line 230 KV or more. Siting permit precedes certification.
KENTUCKY	PSC	PSC	yes	PSC	PSC	yes	PSC	PSC has siting resposibility for 400 KV or greater transmission line.
LOUISIANA	Not Required	*	*	Not Required	*	*	*	
MAINE	PUC	PUC	no	LURC; DEP	LURC; DEP	no	NA	
MARYLAND	PSC	PSC	yes	PSC	PSC	yes	PSC	Required if line >69 KV. Power Plant Research Program evaluates applicatio and presents results at PSC hearing.
MASSACHUSETTS	PUC; Siting Council	PUC; Siting Council	yes	PUC; Siting Council	PUC; Siting Council	yes	PUC; Siting Council	Both agencies must authorize the need and site issues.
MICHIGAN	Not Required	*	*	Not Required	*	*	*	PSC issues certificate of need only if line is outside franchise area. DNR h siting authority on land it administers
MINNESOTA	PUC	PUC	yes	EQB	EQB	yes		Need application must be filed before siting application. Certificate grante before siting approval.

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TABLE I.1 STRUCTURE OF STATE REGULATORY PROCESS
CERTIFICATION AND SITING NEW TRANSMISSION LINE

STATE	STATE CERTIFICATION AUTHORITIES	LEAD AGENCY FOR CERTIFICATION	AUTHORITY TO OVERRIDE OTHER AGENCIES?	STATE SITING AUTHORITIES	LEAD AGENCY FOR SITING	AUTHORITY TO OVERRIDE OTHER AGENCIES?	AGENCY WITH FINAL AUTHORITY FOR TOTAL PROJECT?	CERTIFICATION AND SITING COMMENTS
MISSISSIPPI	PSC	PSC	no	PSC	PSC	no	PSC	
MISSOURI	PSC	PSC	NA	PSC	PSC	NA	PSC	PSC responsible for transmission lines outside utility's service area.
MONTANA	BNRC	BNRC	yes	BNRC	BNRC	yes	BNRC	Primary concern is to impartially balance all relevant factors to make a decision in the best public interest.
NEBRASKA	PRB	PRB	no	Not Required	*	*		Siting vested in local utility directors.
NEVADA	PSC	PSC	no	PSC; NCNR; NEC	PSC	no	PSC	PSC approval contingent upon approval by environmental agencies.
NEW HAMPSHIRE	PUC	PUC	no	Site Evaluation Committee	Site Evaluation Committee	no		Siting approval required before certificate is granted.
NEW JERSEY	BPU	BPU	no	BPU;DOC;DEP (limited)	NA	no	Energy Facility Review Board	BPU responsible only in cases with rejection by local zoning or eminent domain proceedings. DEP involved when location is in Coastal zone. EFRB settles interagency disputes.
NEW MEXICO	PSC	PSC	no	Not Required	*	*	*	
NEW YORK	PSC	PSC	NA	PSC	PSC	NA	PSC	Certification and siting are joint process.
NORTH CAROLINA	Not Required	*	*	Not Required	*	*	*	

* Question is not applicable since certification and/or siting is not required at the state level.

TABLE I.1 . STRUCTURE OF STATE REGULATORY PROCESS
CERTIFICATION AND SITING NEW TRANSMISSION LINE

STATE	STATE CERTIFICATION AUTHORITIES	LEAD AGENCY FOR CERTIFICATION	AUTHORITY TO OVERRIDE OTHER AGENCIES?	STATE SITING AUTHORITIES	LEAD AGENCY FOR SITING	AUTHORITY TO OVERRIDE OTHER AGENCIES?	AGENCY WITH FINAL AUTHORITY FOR TOTAL PROJECT?	CERTIFICATION AND SITING COMMENTS
NORTH DAKOTA	PSC	PSC	yes	PSC	PSC	yes	PSC	Siting authority requires an application for corridor certificate which is followed by a route permit application.
OHIO	Siting Board	Siting Board	NA	Siting Board	Siting Bo.	NA	Siting Board	
OKLAHOMA	Not Required	*	*	Not Required	*	*	*	
OREGON	Siting Council	Siting Council	yes	Siting Council	Siting Council	yes	Siting Council	
PENNSYLVANIA	PUC	PUC	NA	PUC	PUC	NA	PUC	
RHODE ISLAND	PUC: Siting Board	PUC if line <345 KV Siting Board >345 KV	? yes	PUC; Siting Board	PUC if line <345 KV Siting Board >345 KV	? yes	PUC if line <345 KV Siting Board >345 KV	Responsibility depends upon size of line as indicated. Authority to override rejection by PUC not tested.
SOUTH CAROLINA	PSC	PSC	yes	PSC	PSC	yes	PSC	PSC may override the rejection by any other agency if not contrary to statute.
SOUTH DAKOTA	Not Required	*	*	PUC	PUC		*	
TENNESSEE	Not Required	*	*	Not Required	*	*	*	TVA is dominant power producer in state.

* Question is not applicable since certification and/or siting is not required at the state level.

TABLE 1.1 STRUCTURE OF STATE REGULATORY PROCESS CERTIFICATION AND SITING NEW TRANSMISSION LINE

STATE	STATE CERTIFICATION AUTHORITIES	LEAD AGENCY FOR CERTIFICATION	AUTHORITY TO OVERRIDE OTHER AGENCIES?	STATE SITING AUTHORITIES	LEAD AGENCY FOR SITING	AUTHORITY TO OVERRIDE OTHER AGENCIES?	AGENCY WITH FINAL AUTHORITY FOR TOTAL PROJECT?	CERTIFICATION AND SITING COMMENTS
TEXAS	PUC	PUC	NA	PUC	PUC	NA	PUC	Does not apply to lines built by municipal utilities within city limits.
UTAH	PSC	PSC	yes	Not Required	*	*		Some siting responsibility by U.S. BLM.
VERMONT	PSB	PSB	yes	PSB	PSB	yes	PSB	Certification and siting usually simultaneous process.
VIRGINIA	CC	CC	yes	CC	CC	yes	CC	Only lines of 150 KV or more must be approved and certified by CC.
WASHINGTON	Not Required	*	*	EFSEC (limited)	EFSEC	yes	*	Energy Facility Site Evaluation Council has limited responsibility for lines connected to generating stations, or with zoning or environmental problems.
WEST VIRGINIA	PSC	PSC	no	PSC; DNR (limited)	PSC	no		DNR has no "siting authority" but does issue environmental permits,etc.
WISCONSIN	PSC	PSC	no	PSC; DNR	PSC	no	PSC	DNR involved when river crossings, crossings of DNR land, etc. required.
WYOMING	PSC	PSC	no	PSC; DPL; ISC	PSC	no	PSC	DPL involved in siting on state land only. ISC involved when transmission is associated with new power plant.

* Question is not applicable since certification and/or siting is not required at the state level.

TABLE I.1 STRUCTURE OF STATE REGULATORY PROCESS
CERTIFICATION AND SITING NEW TRANSMISSION LINE

STATE	NON-STATE AGENCIES FORMALLY INVOLVED: CONSULTED?	CERTIFICATION AND SITING APPROVED JOINTLY?	ANOTHER FORM OF APPROVAL REQUIRED?	CERTIFICATION NEEDED TO UPGRADE EXISTING LINE?	INTENDED USE OF LINE STATEMENT REQUIRED?	ALTERNATE ROUTES STUDY REQUIRED?	NUMBER OF SEPARATE FILINGS REQUIRED?	PUBLIC HEARINGS REQUIRED?
ALABAMA		*	*	*	*	*	*	*
ALASKA	local authorities; tribal	*	*	*	*	*	*	*
ARIZONA	tribal; U.S. Dept of Interior	*	NA	*	yes	yes	Siting - 1	yes
ARKANSAS	local authorities; others consulted	yes	yes	no	yes	yes	Certification - 1 Siting - 2	yes yes
CALIFORNIA	local; regional;etc. consulted	yes	no	yes	yes	yes	1; joint	yes
COLORADO								
CONNECTICUT								
DELAWARE	local authorities	*	no	*	*	*	Siting - 1, if DOT involved	none
DISTRICT OF COLUMBIA		*					Certification - 1	discretionary
FLORIDA	local authorities; federal power authority consulted	no	no	no	yes	yes	Certification - 1 Siting - 1	yes yes
GEORGIA	U.S. Dept. of Interior	*	*	*	*	*	Siting - 1, if DNR involved	
HAWAII								

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TABLE I.1 STRUCTURE OF STATE REGULATORY PROCESS
CERTIFICATION AND SITING NEW TRANSMISSION LINE

STATE	NON-STATE AGENCIES FORMALLY INVOLVED? CONSULTED?	CERTIFICATION AND SITING APPROVED JOINTLY?	ANOTHER FORM OF APPROVAL REQUIRED?	CERTIFICATION NEEDED TO UPGRADE EXISTING LINE?	INTENDED USE OF LINE STATEMENT REQUIRED?	ALTERNATE ROUTES STUDY REQUIRED?	NUMBER OF SEPARATE FILINGS REQUIRED?	PUBLIC HEARINGS REQUIRED?
IDAHO	local planning and zoning	yes	no	no	yes	no	1; joint	discretionary
ILLINOIS	local authorities consulted	yes	no	no	yes	yes	Certification - 1 Siting - 1	yes yes
INDIANA	local authorities; federal power authority	*	*	*	*	*	*	*
IOWA	City, when inside city	yes	no	yes	yes	no	1; joint	yes, if contested or eminent domain requested
KANSAS	local authorities consulted	yes	yes; Electric Line Report if outside service territory	yes, if line length >5 miles or upgrade >230 KV siting permit required	yes	yes, if line length >5 miles and 230 KV or more	Certification - 1 Siting - 1 Electric Line Report	1; joint
KENTUCKY	none	yes	no	no	yes	no	1; joint if siting required	yes
LOUISIANA		*	*	*	*	*	*	*
MAINE	local/regional authorities consulted	sometimes	yes	yes	yes	yes	Certification - 1 Siting - 2	yes yes
MARYLAND	local authorities consulted	yes	no	no	yes	yes	Certification - 1 Siting - 1	discretionary discretionary
MASSACHUSETTS	local authorities	no	yes	yes	yes	yes	Certification - 2 Siting - 2	yes yes
MICHIGAN	local authorities	*	*	*	*	*	*	*
MINNESOTA		no	yes	yes	yes	yes	Certification - 1 Siting - 1	yes yes

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TABLE I.1 STRUCTURE OF STATE REGULATORY PROCESS
CERTIFICATION AND SITING NEW TRANSMISSION LINE

STATE	NON-STATE AGENCIES FORMALLY INVOLVED? CONSULTED?	CERTIFICATION AND SITING APPROVED JOINTLY?	ANOTHER FORM OF APPROVAL REQUIRED?	CERTIFICATION NEEDED TO UPGRADE EXISTING LINE?	INTENDED USE OF LINE STATEMENT REQUIRED?	ALTERNATE ROUTES STUDY REQUIRED?	NUMBER OF SEPARATE FILINGS REQUIRED?	PUBLIC HEARINGS REQUIRED?
MISSISSIPPI		yes	no	yes	yes	no	1; joint	yes
MISSOURI	none	no	no	yes; outside service territory	yes	no	Certification = 1 Siting = 1	discretionary discretionary
MONTANA	local/tribal/federal authorities consulted	yes	yes	no	yes	yes	Certification = 1 Siting = 1	1; joint
NEBRASKA	local utility board	no	yes; safety	yes	yes	no	Certification = 1	yes
NEVADA	local; regional; tribal	no	yes	no	yes	yes	Certification = 1 Siting = 1	discretionary discretionary
NEW HAMPSHIRE	local/regional authorities consulted	no	no	yes	yes	yes	Certification = 1 Siting = 1	yes yes
NEW JERSEY	city or township	no	no	yes; if zoning involved	yes	yes	1; if any	yes
NEW MEXICO	county; tribal	no	no	yes	yes	yes	Certification = 1	yes
NEW YORK	federal power authority	yes	no	no	yes	yes	1; joint	yes
NORTH CAROLINA		*	*	*	*	*	*	*

* Question is not applicable since certification and/or siting is not required at the state level.

TABLE 1.1 STRUCTURE OF STATE REGULATORY PROCESS
CERTIFICATION AND SITING NEW TRANSMISSION LINE

STATE	NON-STATE AGENCIES FORMALLY INVOLVED? CONSULTED?	CERTIFICATION AND SITING APPROVED JOINTLY?	ANOTHER FORM OF APPROVAL REQUIRED?	CERTIFICATION NEEDED TO UPGRADE EXISTING LINE?	INTENDED USE OF LINE STATEMENT REQUIRED?	ALTERNATE ROUTES STUDY REQUIRED?	NUMBER OF SEPARATE FILINGS REQUIRED?	PUBLIC HEARINGS REQUIRED?
NORTH DAKOTA	none	no	no	no	yes	yes	Certification - 1 Siting - 2	discretionary discretionary
OHIO	local authorities consulted	yes	no	yes	yes	yes	1; joint	yes
OKLAHOMA		*	*	*	*	*	*	*
OREGON	local/regional/tribal/ federal authorities consulted	yes	no	yes	yes	yes	1; joint	yes
PENNSYLVANIA	local/historical/ environmental authorities consulted	yes	no	no	yes	yes	Certification - 1 Siting - 1	1; joint
RHODE ISLAND	local/tribal authorities consulted	yes: >345 KV no: <345 Kv	no: >345 KV yes: <345 Kv	yes	yes	yes	Certification - 1 Siting - 1	1; joint
SOUTH CAROLINA	local authorities and Coastal Council consulted	yes	no	yes	yes	yes	1; joint	yes
SOUTH DAKOTA	local and tribal authorities consulted	*	no	*	yes	yes	Siting - 1	yes
TENNESSEE		*	*	*	*	*	*	*

* Question is not applicable since certification and/or siting is not required at the state level.

TABLE 1.1 STRUCTURE OF STATE REGULATORY PROCESS CERTIFICATION AND SITING NEW TRANSMISSION LINE

STATE	NON-STATE AGENCIES FORMALLY INVOLVED? CONSULTED?	CERTIFICATION AND SITING APPROVED JOINTLY?	ANOTHER FORM OF APPROVAL REQUIRED?	CERTIFICATION NEEDED TO UPGRADE EXISTING LINE?	INTENDED USE OF LINE STATEMENT REQUIRED?	ALTERNATE ROUTES STUDY REQUIRED?	NUMBER OF SEPARATE FILINGS REQUIRED?	PUBLIC HEARINGS REQUIRED?
TEXAS	none	yes	no	yes	yes	yes	1; joint	discretionary
UTAH	local authorities; federal power authority; U.S. Dept. of Interior (BLM)	yes	no	no	yes	no	Certification - 1	discretionary
VERMONT	local and regional authorities consulted	yes	no	yes:if significant environmentally	yes	yes	1; joint	yes
VIRGINIA	local authorities consulted	no	no	yes:if line <150 KV increased >150 KV	yes	yes	1; joint	if requested
WASHINGTON	local authorities	*	no	*	no	yes	Siting - 2	yes
WEST VIRGINIA		yes	no	no	yes	no	Certification - 1 Siting - 1	discretionary discretionary
WISCONSIN	tribal; Dept. of Interior; various other authorities consulted	yes	no	depends on size	yes	yes	1; joint	yes: for large lines
WYOMING	county; tribal; U.S. Dept. of Interior; U.S. Forest Service	yes	no	yes, if >230 KV	yes	no	Certification - 1 Siting - 1 more if DPL, ISC involved	1; joint

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TABLE I.1 STRUCTURE OF STATE REGULATORY PROCESS
CERTIFICATION AND SITING NEW TRANSMISSION LINE

STATE	HEARINGS PARTICIPATION?	METHODS USED ROUTINELY TO EXPEDITE PROCESS?	MOST IMPORTANT FACTOR(S) PROMOTING TIMELY CONSIDERATION?	MOST IMPORTANT FACTOR(S) HINDERING TIMELY CONSIDERATION?
ALABAMA	*	*	*	*
ALASKA	*	*	*	*
ARIZONA	All interested parties		Statutory time frames	Requests for review
ARKANSAS	All interested parties	Joint consideration of required certificates: informal discussions		
CALIFORNIA	All interested parties	Joint consideration of required certificates; Joint consideration and filings/hearings: single agency: informal discussions "prior to" application for approval	One year decision limit	Environmental, system operating requirements
COLORADO				
CONNECTICUT				
DELAWARE	NA	*	*	*
DISTRICT u. COLUMBIA	All interested parties	None		
FLORIDA	All interested parties	Single agency; joint filings/hearings: joint consideration of trans. and gen.; pre-approval of need for power; informal discussions prior to application; coordination with local/regional/federal authorities	Single agency; plan filing and review process	None
GEORGIA	*	*	*	*
HAWAII	All interested parties	informal discussions; coordination with local authorities	Simple process	

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TABLE I.1 STRUCTURE OF STATE REGULATORY PROCESS
CERTIFICATION AND SITING NEW TRANSMISSION LINE

STATE	HEARINGS PARTICIPATION?	METHODS USED ROUTINELY TO EXPEDITE PROCESS?	MOST IMPORTANT FACTOR(S) PROMOTING TIMELY CONSIDERATION?	MOST IMPORTANT FACTOR(S) HINDERING TIMELY CONSIDERATION?
IDAHO	All interested parties	None	Flexibility regarding hearings	The requirement to do the job.
ILLINOIS	public; local officials	Joint consideration of required certificates; single agency; informal discussions "prior to" application allowed but not used	Staff commitment	Incomplete filings
INDIANA	*	*	*	*
IOWA	All affected parties	Single agency; informal discussions; hearings not required if not contested;	Single agency processing	Incomplete filings Lack of staff
KANSAS	All interested parties	Joint consideration of required certificates; Single agency; informal discussions with utilities prior to and during approval process	Statutory time frames	
KENTUCKY	All interested parties	Joint consideration of required certificates; Single agency; informal discussions; joint consideration of projects;	Limited siting responsibility	Controversial issues
LOUISIANA	*	*	*	*
MAINE	All interested parties	Joint consideration of projects; informal discussions	Statutory time frame	
MARYLAND	All interested parties	Joint consideration of required certificates; single agency; joint filings/hearings; informal discussions prior to application; cooridination with local authorities	One-stop hearing process at state level	Lack of statutory time limit for final order
MASSACHUSETTS	All interested parties	Informal discussions with utilities prior to application for approval	Informal joint reviews	Duplication or overlap in formal reviews
MICHIGAN	*	*	*	Projects tied up in local jurisdictions
MINNESOTA	All interested parties	Informal discussions with utilities prior to application for approval; cooridination with local authorities; informal local meetings	Specific filing requirements; statutory time frame; expectation of need	Incomplete filing/information; efforts to delay process; lack of deadlines;

* Question is not applicable since certification and/or siting is not required at the state level.

TABLE I.1 STRUCTURE OF STATE REGULATORY PROCESS CERTIFICATION AND SITING NEW TRANSMISSION LINE

STATE	HEARINGS PARTICIPATION?	METHODS USED ROUTINELY TO EXPEDITE PROCESS?	MOST IMPORTANT FACTOR(S) PROMOTING TIMELY CONSIDERATION?	MOST IMPORTANT FACTOR(S) HINDERING TIMELY CONSIDERATION?
MISSISSIPPI	All interested parties	Joint consideration of required certificates; joint consideration of more than one unrelated transmission project; informal discussions	Single agency certification	Court injunctions
MISSOURI	All interested parties	None	Information requirements	Local opposition
MONTANA	All interested parties	Joint consideration of required certificates; single agency; joint filings/hearings; joint consideration of trans. and gen.; informal discussions; coordination with local authorities and other states; participation in joint state/federal corridor review comm.	Single agency process; joint consideration of need and siting	Statutory requirements for prior findings and for public involvement
NEBRASKA	All interested parties	Joint consideration of transmission and generation projects	Siting vested in local utility board; eminent domain	
NEVADA	All interested parties	Single agency; resource planning process; informal discussions; coordination with local authorities; coordination with federal power authority (Western Area Power Admin.)	Two year cycle Resource Planning Process	Judicial process cumbersome
NEW HAMPSHIRE	All interested parties	Joint consideration of required certificates; joint filings/hearings; joint consideration of trans. and gen. projects; coordination with local authorities; coordination with federal/regional power authorities	Applicant's single presentation before applicable state agencies	
NEW JERSEY	All interested parties	Joint consideration of required certificates; informal discussions with utilities	Ninety day time limit	
NEW MEXICO	All interested parties	Joint consideration of trans. and gen. projects; informal discussions with utilities		
NEW YORK	All interested parties	Joint consideration of required certificates; single agency; joint filings/hearings; informal discussions with utilities; coordination with local/regional/federal authorities	Single agency process	Necessity to submit two alternate routes
NORTH CAROLINA	*	*	*	*

* Question is not applicable since certification and/or siting is not required at the state level.

TABLE 1.1 STRUCTURE OF STATE REGULATORY PROCESS
CERTIFICATION AND SITING NEW TRANSMISSION LINE

STATE	HEARINGS PARTICIPATION?	METHODS USED ROUTINELY TO EXPEDITE PROCESS?	MOST IMPORTANT FACTOR(S) PROMOTING TIMELY CONSIDERATION?	MOST IMPORTANT FACTOR(S) HINDERING TIMELY CONSIDERATION?
NORTH DAKOTA	All interested parties	Single agency; informal discussions with utilities prior to application	Statutory time frame	Two step siting process requiring corridor then route permit
OHIO	All interested parties	Joint consideration of required certificates; single agency; joint filings/hearings; informal discussions with utilities; coordination with local/regional/federal authorities; joint consideration of trans. and generation projects	Single agency process; open hearing process	Aggressive public interest and opposition
OKLAHOMA	*	*	*	*
OREGON	All interested parties	Joint consideration of required certificates; single agency; joint filings/hearings; pre-approval of need for power; pre- approval of rights of way; informal discussions; coordination with local/regional/federal authorities	Single agency process	
PENNSYLVANIA	All interested parties	Joint consideration of required certificates; single agency; informal discussions	Hearing discretion and time limit	More protestants
RHODE ISLAND	All interested parties	Joint consideration of required certificates; single agency; joint filings/hearings; informal discussions prior to application	Statutory time frame	Limited staff resources
SOUTH CAROLINA	All interested parties	Joint consideration of required certificates; single agency; joint consideration of more than one unrelated trans. project; joint consideration of trans. and gen. projects; informal discussions; coordination with local authorities	Predesignated requirements	
SOUTH DAKOTA	All interested parties	Informal discussions with utilities; local authorities consulted	Commission allowed to accept utility environmental assessment	Limited time for environmental review
TENNESSEE	*	*	*	*

* Question is not applicable since certification and/or siting is not required at the state level.

TABLE 1.1 STRUCTURE OF STATE REGULATORY PROCESS
CERTIFICATION AND SITING NEW TRANSMISSION LINE

STATE	HEARINGS PARTICIPATION?	METHODS USED ROUTINELY TO EXPEDITE PROCESS?	MOST IMPORTANT FACTOR(S) PROMOTING TIMELY CONSIDERATION?	MOST IMPORTANT FACTOR(S) HINDERING TIMELY CONSIDERATION?
TEXAS	All interested parties	Joint consideration of required certificates; single agency; joint consideration of more than one unrelated trans. project; informal discussions with utilities	Single agency process; joint consideration and hearing	Limited staff resources
UTAH	All interested parties	Joint consideration of transmission and generation projects	Simple process	Complex issues
VERMONT	All interested parties	Joint consideration of required certificates; single agency; informal discussions prior to application for approval; informal discussions between utilities and intervenors	Single agency approval	Incomplete filing/information
VIRGINIA	All interested parties	Joint consideration of required certificates; joint consideration of trans. and gen. project	Single agency approval	
WASHINGTON	All interested parties	Coordination with local authorities	EFSEC - one stop process local- less red tape	EFSEC- size of process local- number of jurisdictions
WEST VIRGINIA	All interested parties	Joint consideration of trans. and gen. project		
WISCONSIN	All interested parties	Joint consideration of required certificates; single agency; joint filings/hearings; joint consideration of trans. and gen. project; informal discussions; coordinction with local authorities; coordination with agencies from other states for interstate lines	Early involvement by PSC and public in planning process	Incomplete information
WYOMING	All interested parties	Joint consideration of required certificates; single agency; informal discussions; coordination with local authorities	Single agency; joint procedure; continuous contact with utilities by staff during process	Additional agencies involved

* Question is not applicable since certification and/or siting is not required at the state level.

TABLE 1.2 REGULATORY PROCESS FOR INTERSTATE FACILITIES CERTIFICATION AND SITING TRANSMISSION LINES

APPROVAL CRITERIA ---NEW TRANSMISSION LINE FOR UTILITY'S OWN SERVICE TERRITORY?	
Need For Power	31
State Environmental Regulations	27
Public Environmental Concerns	29
State Land Use Requirements	22
Local Land Use and Zoning	26
"Public Interest"	27
System Reliability	6
Economics/Cost	5
Available Alternatives	4
Safety Considerations	3
Long Range Planning	2
Size of Line	3
Other Factors	6
Not Applicable	10
No Response	4

ADDITIONAL APPROVAL CRITERIA --- NEW INTER-UTILITY TRANSMISSION LINES FOR SALES --- REQUIRED	
Distribution Power Obligations	17
Utility Service Reliability	20
Need For Power	20
Opportunity To Sell Existing Power	15
Opportunity To Sell Future Power	15
Opportunity To Profit From Wheeling	13
Access By Public Utilities	10
Access By Any Other Utility	8
"Public Interest"	20
Economics/Cost	2
Long Range Planning	2
System Reliability	1
Safety Considerations	1
Other Factors	5
None	3
Not Applicable	12
No Response	4

ADDITIONAL APPROVAL CRITERIA --- NEW INTER-UTILITY TRANSMISSION LINES FOR SALES --- CONSIDERED	
Distribution Power Obligations	9
Utility Service Reliability	8
Need For Power	7
Opportunity To Sell Existing Power	10
Opportunity To Sell Future Power	10
Opportunity To Profit From Wheeling	11
Access By Public Utilities	8
Access By Any Other Utility	9
"Public Interest"	7
All Other Relevant Factors	4
Other Factors	1
None	2
Not Applicable	11
No Response	18

APPROVAL CRITERIA FOR CERTIFICATION VARYS WHEN LINE IS INTERSTATE?	
Yes	2
No	29
Sometimes	3
Not Applicable	13
No Response	3
Unknown	1

APPROVAL CRITERIA FOR SITING VARYS WHEN LINE IS INTERSTATE?	
Yes	1
No	32
Sometimes	1
Not Applicable	11
No Response	6

APPROVAL CRITERIA FOR EMINENT DOMAIN VARYS WHEN LINE IS INTERSTATE?	
Yes	0
No	29
Unknown	1
Not Applicable	13
No Response	7

APPROVAL CRITERIA CONSIDERS INTERSTATE NEED FOR POWER IN CASE OF MULTI-STATE UTILITY ?	
Yes	4
No	29
Not Applicable	12
No Response	6

"PUBLIC INTEREST" STANDARD FOR INTERSTATE LINES?	
No Difference	24
More Stringent	1
More Difficult In Practice	3
Not Applicable	19
No Response	4

TABLE 1.2 REGULATORY PROCESS FOR INTERSTATE FACILITIES
CERTIFICATION AND SITING TRANSMISSION LINES

STATE	APPROVAL CRITERIA ---NEW TRANSMISSION LINE FOR UTILITY'S OWN SERVICE TERRITORY	ADDITIONAL APPROVAL CRITERIA --- NEW INTER-UTILITY TRANSMISSION LINES FOR SALES --- REQUIRED	ADDITIONAL APPROVAL CRITERIA --- NEW INTER-UTILITY TRANSMISSION LINES FOR SALES --- CONSIDERED	APPROVAL CRITERIA FOR CERTIFICATION VARYS WHEN LINE IS INTERSTATE?
	See Answer Code At End Of Question	See Answer Code At End Of Question	See Answer Code At End Of Question	
ALABAMA	*	*	*	*
ALASKA	*	*	*	*
ARIZONA	only 115KV or greater state and Commission regulations	none	none	*
ARKANSAS	1.2.3.4.5.6	1. 3.4.5.6. 9	2. 7.8 .	yes
CALIFORNIA	1.2.3.4.5. economic development health and safety system reliability	1.2. 4.5.6 . economic development health and safety system reliability	none	yes. if line will not directly serve in-state customers
COLORADO				
CONNECTICUT				
DELAWARE	*	*	*	*
DISTRICT OF COLUMBIA				
FLORIDA	1.2.3.4.5.	need for the line	1.2.3.4.5.6.7.8.9	no
GEORGIA	*	*	*	*
HAWAII	2.3.4.5.6	NA	NA	NA
IDAHO	6	9	any relevant factor requested	no
ILLINOIS	1.2. 6	3. 9	1.2. 4.5.6 .	no
INDIANA	*	*	*	*

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* Question is not applicable since certification and/or siting is not required at the state level.

TABLE 1.2 REGULATORY PROCESS FOR INTERSTATE FACILITIES
CERTIFICATION AND SITING TRANSMISSION LINES

STATE	APPROVAL CRITERIA ---NEW TRANSMISSION LINE FOR UTILITY'S OWN SERVICE TERRITORY See Answer Code At End Of Question	ADDITIONAL APPROVAL CRITERIA --- NEW INTER-UTILITY TRANSMISSION LINES FOR SALES --- REQUIRED See Answer Code At End Of Question	ADDITIONAL APPROVAL CRITERIA --- NEW INTER-UTILITY TRANSMISSION LINES FOR SALES --- CONSIDERED See Answer Code At End Of Question	APPROVAL CRITERIA FOR CERTIFICATION VARYS WHEN LINE IS INTERSTATE?
IOWA	1. 5.6 method of supply alternate routes	2.3 relation to utility planning relation to plans for future system		no
KANSAS	1. 3. 5. size of line safety considerations	2.3.4.5	1. 6.7.8.9	no experience
KENTUCKY	1. 3.	9	1.2.3.4.5.6	no
LOUISIANA	*	*	*	*
MAINE	1.2.3.4.5.6 size of line and purpose system reliability and capability route description and alternates description of line and cost	9	all other relevant factors	no
MARYLAND	1.2.3. economics; aesthetics system reliability	3		no
MASSACHUSETTS	1.2.3. 5.6	1.2.3	4.5.6.7.8	no
MICHIGAN	*	*	*	*
MINNESOTA	1.2.3.4.5.6 available alternatives; costs safety; federal policies	1.2.3.4.5.6.7.8.9 cost and environmental effects		no
MISSISSIPPI	1. 6 compatibility	1.2. 4.5.6. 9		yes: if line will not serve customers in state
MISSOURI	1. 3. 6	1.2.3.4.5.6.7.8.9		no
MONTANA	1.2.3.4.5.6 alternatives system reliability	1.2.3.4.5.6. 9 no opportunity to purchase power		no

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TABLE 1.2 REGULATORY PROCESS FOR INTERSTATE FACILITIES CERTIFICATION AND SITING TRANSMISSION LINES

STATE	APPROVAL CRITERIA ---NEW TRANSMISSION LINE FOR UTILITY'S OWN SERVICE TERRITORY	ADDITIONAL APPROVAL CRITERIA --- NEW INTER-UTILITY TRANSMISSION LINES FOR SALES --- REQUIRED	ADDITIONAL APPROVAL CRITERIA --- NEW INTER-UTILITY TRANSMISSION LINES FOR SALES --- CONSIDERED	APPROVAL CRITERIA FOR CERTIFICATION VARYS WHEN LINE IS INTERSTATE?
	See Answer Code At End Of Question	See Answer Code At End Of Question	See Answer Code At End Of Question	
NEBRASKA	1. .	2. 7 .		no
NEVADA	1.2.3.4.5.6	1.2.3. 9 opportunity to sell future power	4.5.6. 9 opportunity to sell future power	no
NEW HAMPSHIRE	1.2.3.4.5.6	1.2.3.4.5.6.7.8.9		no
NEW JERSEY	1.2.3.4.5.6	NA	NA	no
NEW MEXICO	1.2.3.4.5.6	1.2.3.4.5.6.7.8.9		no
NEW YORK	2.3.4.5	1.2.3. .		no
NORTH CAROLINA	*	*	*	*
NORTH DAKOTA	1.2.3.4.5.6		all relevant factors	NA
OHIO	1.2.3.4.5.6 agricultural concerns	1.2.3.4.5.6.7.8.9		no
OKLAHOMA	*	*	*	*
OREGON	1.2.3.4.5.6	1.2.3.4.5.6.7.8.9		no
PENNSYLVANIA	1.2.3.4.5.6	9	1.2.3.4.5.6.7.8 .	no
RHODE ISLAND	1.2.3.4.5.6	none	1.2.3.4.5.6.7.8.9	no
SOUTH CAROLINA	1.2. 4 .	none	1.2.3.4.5.6.7.8.9	no
SOUTH DAKOTA	2.3.4.5.6	1.2. .	3.4.5.6.7.8.9	no
TENNESSEE	*	* .	*	*

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TABLE 1.2 REGULATORY PROCESS FOR INTERSTATE FACILITIES
CERTIFICATION AND SITING TRANSMISSION LINES

STATE	APPROVAL CRITERIA ---NEW TRANSMISSION LINE FOR UTILITY'S OWN SERVICE TERRITORY	ADDITIONAL APPROVAL CRITERIA --- NEW INTER-UTILITY TRANSMISSION LINES FOR SALES --- REQUIRED	ADDITIONAL APPROVAL CRITERIA --- NEW INTER-UTILITY TRANSMISSION LINES FOR SALES --- CONSIDERED	APPROVAL CRITERIA FOR CERTIFICATION VARYS WHEN LINE IS INTERSTATE?
	See Answer Code At End Of Question	See Answer Code At End Of Question	See Answer Code At End Of Question	
TEXAS	1. 3. 6 adequacy of existing service historical and aesthetic values lower cost or improved service	none	1,2,3.4.5,6,7,8,9	no
UTAH		1.2.3.4.5.6.7.8.9		yes
VERMONT	1.2.3.4.5.6 economics; long range planning regional development stability and reliability	same as for distribution line	all relevant factors	no
VIRGINIA	1. 3. 5 .	2.3.4.5. 9 line 150 KV or more in size		no
WASHINGTON	2. 5 .			no
WEST VIRGINIA	1.2.3. 6	1. 3. 9		no
WISCONSIN	1.2.3.4.5.6 consistency with long range plans	1.2.3.4.5.6.7.8.9		yes; if line will not serve customers in state
WYOMING	1.2.3.4.5.6	2.3.4.5.6.7. 9	1. 8 .	no

Answer Code for this Question:

1. need for power
2. state environmental regulations
3. public environmental concerns
4. state land use requirements
5. local land use and zoning
6. "public interest"

Answer Code for this Question:

1. distribution power obligations
2. utility service reliability
3. need for power
4. opportunity to sell existing power
5. opportunity to sell future power
6. opportunity to profit from wheeling
7. access by public utilities
8. access by any other utility
9. "public interest"

Answer Code for this Question:

1. distribution power obligations
2. utility service reliability
3. need for power
4. opportunity to sell existing power
5. opportunity to sell future power
opportunity to profit from wheeling
access by public utilities
access by any other utility
9. "public interest"

* Question is not applicable since certification and/or siting is not required at the state

TABLE 1.2 REGULATORY PROCESS FOR INTERSTATE FACILITIES CERTIFICATION AND SITING TRANSMISSION LINES

STATE	APPROVAL CRITERIA FOR SITING VARYS WHEN LINE IS INTERSTATE?	APPROVAL CRITERIA FOR EMINENT DOMAIN VARYS WHEN LINE IS INTERSTATE?	APPROVAL CRITERIA CONSIDERS INTERSTATE NEED FOR POWER IN CASE OF MULTI-STATE UTILITY ?	DEFINE "PUBLIC INTEREST" AS USED FOR APPROVAL CRITERIA	"PUBLIC INTEREST" STANDARD FOR INTERSTATE LINES?
ALABAMA	*	*	*	*	*
ALASKA	*	*	*	*	*
ARIZONA	no	depends upon condemnation law	no		no difference
ARKANSAS	yes	no	yes		
CALIFORNIA	no	no	no	NA	NA
COLORADO					
CONNECTICUT					
DELAWARE	*	*	*	*	*
DISTRICT OF COLUMBIA					
FLORIDA	no	no	no	Consideration of reliable service at the lowest cost; balanced with concern for need and environmental effects.	no difference
GEORGIA	*	*	*	*	*
HAWAII	NA	NA	NA	The need of the project is for the good of the majority.	NA
IDAHO	no	no	no	not definable	no difference
ILLINOIS	no	no	no	Primarily determined in terms of lowest present value of future revenue requirements with consideration for reliability and land use.	no difference
INDIANA	*	*	*	*	*

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TABLE 1.2 REGULATORY PROCESS FOR INTERSTATE FACILITIES
CERTIFICATION AND SITING TRANSMISSION LINES

STATE	APPROVAL CRITERIA FOR SITING VARYS WHEN LINE IS INTERSTATE?	APPROVAL CRITERIA FOR EMINENT DOMAIN VARYS WHEN LINE IS INTERSTATE?	APPROVAL CRITERIA CONSIDERS INTERSTATE NEED FOR POWER IN CASE OF MULTI-STATE UTILITY ?	DEFINE "PUBLIC INTEREST" AS USED FOR APPROVAL CRITERIA	"PUBLIC INTEREST" STANDARD FOR INTERSTATE LINES?
IOWA	no	no	no	not defined	no difference
KANSAS				Necessity and reasonableness of location; cost, utility, and environmental impact.	no difference
KENTUCKY	no	non-jurisdictional	NA	not defined	no difference
LOUISIANA	*	*	*	*	*
MAINE	no		no	not defined	no difference
MARYLAND	no	no	no	NA	NA
MASSACHUSETTS	no	no	no	Least cost balanced against adverse environmental impacts.	more stringent
MICHIGAN	*	*	*	*	*
MINNESOTA			no	not defined	no difference
MISSISSIPPI	no	no	no	Both needed and beneficial.	more difficult in practice
MISSOURI	no	no	no	Need to serve customers.	no difference
MONTANA	no	no	no	not defined	no difference

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TABLE 1.2 REGULATORY PROCESS FOR INTERSTATE FACILITIES CERTIFICATION AND SITING TRANSMISSION LINES

STATE	APPROVAL CRITERIA FOR SITING VARYS WHEN LINE IS INTERSTATE?	APPROVAL CRITERIA FOR EMINENT DOMAIN VARYS WHEN LINE IS INTERSTATE?	APPROVAL CRITERIA CONSIDERS INTERSTATE NEED FOR POWER IN CASE OF MULTI-STATE UTILITY ?	DEFINE "PUBLIC INTEREST" AS USED FOR APPROVAL CRITERIA	"PUBLIC INTEREST" STANDARD FOR INTERSTATE LINES?
NEBRASKA	no	no	no	NA	NA
NEVADA	no	no	no	Minimization of present worth of revenue requirements of applicant.	no difference
NEW HAMPSHIRE	no	no	no	Impact on regional development, historical sites, air and water quality.	no difference
NEW JERSEY	no	no		not defined	
NEW MEXICO			no	not defined	no difference
NEW YORK	no	no	no	NA	NA
NORTH CAROLINA	*	*	*	*	*
NORTH DAKOTA	no	no	no	not defined	no difference
OHIO	no	no	yes	Embraces various social, health, safety, political, and land value factors.	no difference
OKLAHOMA	*	*	*	*	*
OREGON	no	NA	no	not defined	
PENNSYLVANIA	no	no	no	Necessary or proper for service, convenience, or safety of the public.	no difference
RHODE ISLAND	no	no	yes	No definition - subjective	no difference
SOUTH CAROLINA	no	no	no	NA	NA
SOUTH DAKOTA	yes; if line will not serve customers in state	no		NA	NA
TENNESSEE	*	*	*	*	*

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TABLE I.2 REGULATORY PROCESS FOR INTERSTATE FACILITIES
CERTIFICATION AND SITING TRANSMISSION LINES

STATE	APPROVAL CRITERIA FOR SITING VARYS WHEN LINE IS INTERSTATE?	APPROVAL CRITERIA FOR EMINENT DOMAIN VARYS WHEN LINE IS INTERSTATE?	APPROVAL CRITERIA CONSIDERS INTERSTATE NEED FOR POWER IN CASE OF MULTI-STATE UTILITY ?	DEFINE "PUBLIC INTEREST" AS USED FOR APPROVAL CRITERIA	"PUBLIC INTEREST" STANDARD FOR INTERSTATE LINES?
TEXAS	no	no	no	NA	NA
UTAH	no	no	no	Lowest long term cost with reasonable service.	more difficult in practice
VERMONT	no	no	no	Net present value of economic savings and/or reliability improvement.	no difference
VIRGINIA	no	NA	no	not defined	no difference
WASHINGTON	no	no	no	NA	NA
WEST VIRGINIA	no	no	no	not defined	no difference
WISCONSIN	no	no	yes	Balance of need for service, economics, environmental factors, land use, etc.	more difficult in practice
WYOMING	no		no	Public convenience and necessity. Meets the statutory requirements of adequacy, safety and efficiency.	no difference

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SUMMARY REPORT

TABLE I.3 STATE REGULATORY EXPERIENCE
CERTIFICATION AND SITING TRANSMISSION LINES

TYPICAL DAYS FROM INITIAL FILING TO FINAL APPROVAL :

	CERTIFICATION?		SITING?		JOINT?	
	MIN.	MAX.	MIN.	MAX.	MIN.	MAX.
AVG	137	268	132	319	120	336
STD	97	142	59	110	65	211

POSSIBLE TIMEFRAME FOR APPROVAL (SHORTEST-LONGEST) :

	CERTIFICATION?		SITING?		JOINT?	
	MIN.	MAX.	MIN.	MAX.	MIN.	MAX.
AVG	82	480	120	545	154	495
STD	76	506	71	488	165	390

HOW MANY PROJECTS HAVE BEEN APPROVED IN YOUR STATE :

	WITHIN THE LAST YEAR?	WITHIN THE LAST 5 YEARS?	WITHIN THE LAST 10 YEARS?	MORE THAN 10 YEARS AGO?
SUM	73	317	422	331
AVG	2	10	16	16
STD	4	14	24	42

HOW MANY PROJECTS APPROVED WITHIN LAST 5 YEARS ARE NOW:

	LAND ACQUISITION PHASE ?	UNDER CONSTRUCTION?	COMPLETED?	CANCELLED/ MOTHBALLED?
SUM	17	71	172	11
AVG	1	3	7	0
STD	2	4	13	1

HOW MANY REQUESTS ARE PENDING APPROVAL FOR:

	CERTIFICATION ONLY?	SITING ONLY?	BOTH?	OTHER?
SUM	10	8	49	17
AVG	0	0	2	1
STD	1	1	5	2

REQUESTS FOR CERTIFICATION OR SITING OF INTERSTATE LINE WITHIN LAST 5 YEARS?	
None	11
Yes, one other state	15
Yes, more than one other	9
Not Applicable	11
No Response	5

TABLE 1.3 STATE REGULATORY EXPERIENCE
CERTIFICATION AND SITING TRANSMISSION LINES

STATE	REQUESTS FOR CERTIFICATION OR SITING OF INTERSTATE LINE WITHIN LAST 5 YEARS?	TYPICAL DAYS FROM INITIAL FILING TO FINAL APPROVAL :						POSSIBLE TIMEFRAME FOR APPROVAL (SHORTEST-LONGEST) :					
		CERTIFICATION?		SITING?		JOINT?		CERTIFICATION?		SITING?		JOINT?	
		MIN.	MAX.	MIN.	MAX.	MIN.	MAX.	MIN.	MAX.	MIN.	MAX.	MIN.	MAX.
ALABAMA	*	*	*	*	*	*	*	*	*	*	*	*	*
ALASKA	*	*	*	*	*	*	*	*	*	*	*	*	*
ARIZONA	yes, only one other state	*	*	60	180	*	*	*	*	90	180	*	*
ARKANSAS	none					60	180					40	?
COLORADO													
CONNECTICUT													
CALIFORNIA	yes, more than one other state					180	365					270	730
DELAWARE	*	*	*	*	*	*	*	*	*	*	*	*	*
DISTRICT OF COLUMBIA				*	*	*	*			*	*	*	*
FLORIDA	yes, only one other state	60	180	180	365			1	60	180	210	180	210
GEORGIA	*	*	*	*	*	*	*	*	*	*	*	*	*
HAWAII	NA					60	180					60	90
IDAHO	none	?	?	?	?	?	?	?	?	?	?	?	?
ILLINOIS	yes, only one other state					180	365					180	450
INDIANA	*	*	*	*	*	*	*	*	*	*	*	*	*
IOWA	yes, only one other state					245	365					150	730
KANSAS	none					60	180					60	120
KENTUCKY	none					60	180					30	180
LOUISIANA	*	*	*	*	*	*	*	*	*	*	*	*	*
MAINE	none	60	180	60	180			20	180	90	180		
MARYLAND	yes, more than one other state					60	180					60	180
MASSACHUSETTS	yes, more than one other state	365	545	180	365			180	730	90	730		

* Question is not applicable since certification and/or siting is not required at the state level.

TABLE 1.3 STATE REGULATORY EXPERIENCE
CERTIFICATION AND SITING TRANSMISSION LINES

STATE	REQUESTS FOR CERTIFICATION OR SITING OF INTERSTATE LINE WITHIN LAST 5 YEARS?	TYPICAL DAYS FROM INITIAL FILING TO FINAL APPROVAL :						POSSIBLE TIMEFRAME FOR APPROVAL (SHORTEST-LONGEST) :					
		CERTIFICATION?		SITING?		JOINT?		CERTIFICATION?		SITING?		JOINT?	
		MIN.	MAX.	MIN.	MAX.	MIN.	MAX.	MIN.	MAX.	MIN.	MAX.	MIN.	MAX.
MICHIGAN	*	*	*	*	*	*	*	*	*	*	*	*	*
MINNESOTA	certification - no	180	365	180	365			180	365	180	365		
MISSISSIPPI	yes, only one other state					60	180					45	180
MISSOURI	none	180	365	60	180			30	375	30	375		
MONTANA	yes, only one other state					NA	960					545	1460
NEBRASKA	yes, more than one other state	1	60					1	160				
NEVADA	yes, only one other state	60	180	60	180			60	365	60	180		
NEW HAMPSHIRE	yes, only one other state		60		545				60		485		
NEW JERSEY						180	365					180	365
NEW MEXICO	yes, only one other state	180	365	*	*	*	*	60	365	*	*	*	*
NEW YORK	none					NA	912					730	1460
NORTH CAROLINA	*	*	*	*	*	*	*	*	*	*	*	*	*
NORTH DAKOTA	yes, more than one other state	60	180	NA	375			180	365	270	730		
OHIO	yes, more than one other state					180	365					150	1095
OKLAHOMA	*	*	*	*	*	*	*	*	*	*	*	*	*
OREGON	yes, more than one other state					180	365					180	365
PENNSYLVANIA	yes, only one other state					60	180					60	375
RHODE ISLAND	none					NA	425					180	425
SOUTH CAROLINA						60	180					60	90
SOUTH DAKOTA	yes, only one other state	*	*	180	365	*	*	*	*	120	365	*	*
TENNESSEE	*	*	*	*	*	*	*	*	*	*	*	*	*

* Question is not applicable since certification and/or siting is not required at the state level.

TABLE I.3 STATE REGULATORY EXPERIENCE
CERTIFICATION AND SITING TRANSMISSION LINES

STATE	REQUESTS FOR CERTIFICATION OR SITING OF INTERSTATE LINE WITHIN LAST 5 YEARS?	TYPICAL DAYS FROM INITIAL FILING TO FINAL APPROVAL :						POSSIBLE TIMEFRAME FOR APPROVAL (SHORTEST-LONGEST) :					
		CERTIFICATION?		SITING?		JOINT?		CERTIFICATION?		SITING?		JOINT?	
		MIN.	MAX.	MIN.	MAX.	MIN.	MAX.	MIN.	MAX.	MIN.	MAX.	MIN.	MAX.
TEXAS	none					60	180					60	365
UTAH	yes, only one other state	180	365	*	*	*	*	14	730	*	*	*	*
VERMONT	yes, more than one other state					180	365					90	730
VIRGINIA	yes, only one other state	180	365	180	365			180	2008	180	2008		
WASHINGTON	yes, more than one other state	*	*	180	365	*	*	*	*	30	730	*	*
WEST VIRGINIA	none					180	365					150	365
WISCONSIN	yes, only one other state					180	365					60	545
WYOMING	yes, only one other state					60	180					30	375

* Question is not applicable since certification and/or siting is not required at the state level.

TABLE I.3 STATE REGULATORY EXPERIENCE
CERTIFICATION AND SITING TRANSMISSION LINES

STATE	HOW MANY PROJECTS HAVE BEEN APPROVED IN YOUR STATE :				HOW MANY PROJECTS APPROVED WITHIN LAST 5 YEARS ARE NOW:				HOW MANY REQUESTS ARE PENDING APPROVAL FOR:			
	WITHIN THE LAST YEAR?	WITHIN THE LAST 5 YEARS?	WITHIN THE LAST 10 YEARS?	MORE THAN 10 YEARS AGO?	LAND ACQUISITION PHASE ?	UNDER CONSTRUCTION?	COMPLETED?	CANCELLED/ MOTHBALLED?	CERTIFICATION ONLY?	SITING ONLY?	BOTH?	OTHER?
ALABAMA	*	*	*	*	*	*	*	*	*	*	*	*
ALASKA	*	*	*	*	*	*	*	*	*	*	*	*
ARIZONA	3	20	29	43	7	4	2	1	*	1	*	0
ARKANSAS	5	11	16	7	0	2	9	0	0	0	0	0
COLORADO												
CONNECTICUT												
CALIFORNIA	6	15	25	NA	0	10	4	1	0	0	15	3
DELAWARE	*	*	*	*	*	*	*	*	*	*	*	*
DISTRICT OF COLUMBIA										*	*	
FLORIDA	0	4	NA	NA	0	0	4	0	0	1	0	0
GEORGIA	*	*	*	*	*	*	*	*	*	*	*	*
HAWAII												
IDAHO	0	0	1	?					0	0	0	0
ILLINOIS	?	?	?	?	?	?	?	?	1	1	0	0
INDIANA	*	*	*	*	*	*	*	*	*	*	*	*
IOWA	15	75	?	?	0	10	65	0	0	0	0	13
KANSAS	0	1	4	0	0	0	1	0	0	0	0	0
KENTUCKY	0	7	10	?	0	0	7	0	0	0	0	0
LOUISIANA	*	*	*	*	*	*	*	*	*	*	*	*
MAINE	1	5	NA	NA	?	?	?	?	3	0	0	0
MARYLAND	0	3	17	44	0	0	3	0	0	0	3	0
MASSACHUSETTS	4	25	50	?	0	15	5	5	0	5	0	0

* Question is not applicable since certification and/or siting is not required at the state level.

TABLE I.3 STATE REGULATORY EXPERIENCE
CERTIFICATION AND SITING TRANSMISSION LINES

STATE	HOW MANY PROJECTS HAVE BEEN APPROVED IN YOUR STATE :				HOW MANY PROJECTS APPROVED WITHIN LAST 5 YEARS ARE NOW:				HOW MANY REQUESTS ARE PENDING APPROVAL FOR:			
	WITHIN THE LAST YEAR?	WITHIN THE LAST 5 YEARS?	WITHIN THE LAST 10 YEARS?	MORE THAN 10 YEARS AGO?	LAND ACQUISITION PHASE ?	UNDER CONSTRUCTION?	COMPLETED?	CANCELLED/ MOTHBALLED?	CERTIFICATION ONLY?	SITING ONLY?	BOTH?	OTHER?
MICHIGAN	*	*	*	*	*	*	*	*	*	*	*	*
MINNESOTA	0	0	2	0	0	0	0	0	0	0	0	0
MISSISSIPPI	11	22	34	193	?	3	?	?	0	0	0	0
MISSOURI	1	4	?	?	?	?	?	?	0	*	*	0
MONTANA	1	6	11	2	3	2	1	0	0	*	*	1
NEBRASKA	?	?	?	?	?	?	?	?				
NEVADA	1	2	5	15	2	0	0	0	1	0	0	0
NEW HAMPSHIRE	0	3	0	1	0	3	0	0	1	0	0	0
NEW JERSEY	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
NEW MEXICO	0	5	0	?	2	0	3	0	2	*	*	0
NEW YORK	1	4	5	?	0	1	3	0	0	0	1	0
NORTH CAROLINA	*	*	*	*	*	*	*	*	*	*	*	*
NORTH DAKOTA	0	5	6	0	0	5	0	0	0	0	0	0
OHIO	1	15	120	0	0	11	4	0	0	0	0	0
OKLAHOMA	*	*	*	*	*	*	*	*	*	*	*	*
OREGON	0	1	2	0	NA	NA	NA	NA	0	0	2	0
PENNSYLVANIA	?	?	?	?	?	?	?	?			2	
RHODE ISLAND	0	1	0	0	1	0	0	0	0	0	0	0
SOUTH CAROLINA	3	9	23	15	0	0	9	0	0	0	0	0
SOUTH DAKOTA	0	4	0	0	0	0	4	0	*	0	*	0
TENNESSEE	*	*	*	*	*	*	*	*	*	*	*	*

* Question is not applicable since certification and/or siting is not required at the state level.

TABLE I.3 STATE REGULATORY EXPERIENCE
CERTIFICATION AND SITING TRANSMISSION LINES

STATE	HOW MANY PROJECTS HAVE BEEN APPROVED IN YOUR STATE : WITHIN THE LAST YEAR?	WITHIN THE LAST 5 YEARS?	WITHIN THE LAST 10 YEARS?	MORE THAN 10 YEARS AGO?	HOW MANY PROJECTS APPROVED WITHIN LAST 5 YEARS ARE NOW: LAND ACQUISITION PHASE ?	UNDER CONSTRUCTION?	COMPLETED?	CANCELLED/ MOTHBALLED?	HOW MANY REQUESTS ARE PENDING APPROVAL FOR: CERTIFICATION ONLY?	SITING ONLY?	BOTH?	OTHER?
TEXAS	?	?	?	?	?	?	?	?	0	0	20	0
UTAH	0	1	0	0	0	0	1	0	1	*	*	0
VERMONT	1	5	?	?	0	0	5	0	0	0	0	0
VIRGINIA	3	12	24	0	0	?	?	0	0	0	3	0
WASHINGTON	0	0	1	1	0	0	0	1	0	*	*	0
WEST VIRGINIA	0	0	3	0	NA	NA	NA	NA	0	0	0	0
WISCONSIN	7	19	34	10	2	2	15	0	0	0	3	0
WYOMING	9	33	0	0	0	3	27	3	1	0	0	0

* Question is not applicable since certification and/or siting is not required at the state level.

SUMMARY REPORT

TABLE II.1 INDEPENDENT STATE PLANNING AND FORECASTING ACTIVITIES

INDEPENDENT FORECASTING AGENCIES	
PUC	18
Energy Office	12
Siting Board	1
Other	11
None	16
No Response	2

FREQUENCY OF FORECASTS ?	
< Every 2 Years	16
Every 2 to 5 Years	10
> Every 5 Years	0
With Certification	3
Rate Case Only	1
Not Applicable	17
No Response	4

TIMEFRAME(S) OF FORECASTS ?	
5 Years	3
10 Years	10
15 Years	8
20 Years	14
25 Years	1
Not Applicable	17
No Response	4

ELEMENTS INCLUDED IN STATE PLAN ?	
Intrastate Supply and Demand	25
Interstate Supply and Demand	12
Other Sources of Power	17
Need/Source of Generating Capacity	20
Transmission Capacity Needs	13
Intrastate Electricity Supply	2
Other Factors	2
Not Applicable	19
No Response	5

PLANS INCLUDE TRANSMISSION CAPACITY REGARDING ?	
Anticipated Supply and Demand	12
Existing Supply and Demand	2
Both Anticipated and Existing	2
Not Applicable	22
No Response	13

PLANS USED IN CERTIFICATION AND SITING OF NEW GENERATING PLANT ?	
Yes	19
No	0
Not Applicable	20
No Response	12

RESULTS USED IN CERTIFICATION AND SITING OF NEW TRANSMISSION PLANT ?	
Yes	15
No	0
Not Applicable	19
No Response	17

RESULTS USED IN RATEMAKING PROCESS ?	
Yes	11
No	0
Not Applicable	19
No Response	21

STATE INVOLVED IN EXTRA-STATE PLANNING PROCESS WITH ?	
No	24
Yes, Other States	8
Yes, Regional	8
Yes, Utilities etc.	11
Not Applicable	0
No Response	7

TABLE II.1 INDEPENDENT STATE PLANNING AND FORECASTING ACTIVITIES

STATE	INDEPENDENT FORECASTING AGENCIES	FREQUENCY OF FORECASTS ?	TIMEFRAME(S) OF FORECASTS ?	ELEMENTS INCLUDED IN STATE PLAN ?
ALABAMA	Energy Office; DECA	every 2 to 5 years	10 years 20 years	anticipated demand in state anticipated supply in state
ALASKA	Alaska Power Authority	less than every 2 years	10 years 20 years	anticipated demand in state anticipated supply in state generation capacity needed potential intrastate sources
ARIZONA	none	*	*	*
ARKANSAS	none	*	*	*
CALIFORNIA	Energy Commission	every 2 to 5 years	5 years 12 years 20 years	intrastate supply and demand interstate supply and demand other sources of power needs/sources of generating capacity transmission capacity needs
COLORADO				
CONNECTICUT				
DELAWARE	none	*	*	*
DISTRICT OF COLUMBIA	Energy Office	less than every 2 years	10 years	
FLORIDA	FEPCG	less than every 2 years	10 years 20 years	intrastate supply and demand interstate supply and demand other sources of power needs/sources of generating capacity transmission capacity needs conservation load management
GEORGIA	none	*	*	*
HAWAII	none	*	*	*
IDAHO	Northwest Power Council	less than every 2 years	20 years	intrastate supply and demand interstate supply and demand other sources of power needs/sources of generating capacity transmission capacity needs
ILLINOIS	PUC; DOE; DNR	every 2 to 5 years	20 years	intrastate supply and demand interstate supply and demand other sources of power needs/sources of generating capacity transmission capacity needs

* Question is not applicable since no forecasts are performed by state.

TABLE II.1 INDEPENDENT STATE PLANNING AND FORECASTING ACTIVITIES

STATE	INDEPENDENT FORECASTING AGENCIES	FREQUENCY OF FORECASTS ?	TIMEFRAME(S) OF FORECASTS ?	ELEMENTS INCLUDED IN STATE PLAN ?
INDIANA	PUC Univ. Forecasting Group	less than every 2 years	20 years	intrastate supply and demand interstate supply and demand other sources of power needs/sources of generating capacity transmission capacity needs
IOWA	none	*	*	*
KANSAS	PUC	less than every 2 years	5 years	intrastate supply and demand other sources of power needs/sources of generating capacity transmission capacity needs
KENTUCKY	none	*	*	*
LOUISIANA				
MAINE	Energy Office; PUC	less than every 2 years	15 years	intrastate supply and demand interstate supply and demand other sources of power needs/sources of generating capacity transmission capcity needs
MARYLAND	PUC; DNR	every 2 to 5 years	10 years	intrastate supply and demand interstate supply and demand other sources of power needs/sources of generating capacity transmission capacity needs
MASSACHUSETTS	Energy Office	less than every 2 years	15 years	intrastate supply and demand interstate supply and demand other sources of power needs/sources of generating capacity transmission capacity needs
MICHIGAN	PUC; Energy Office	during rate cases only	future test year	NA
MINNESOTA	DEED; DPS	during certification only	15 years	NA
MISSISSIPPI	ETB; PUC			
MISSOURI	none	*	*	*

* Question is not applicable since no forecasts are performed by state.

TABLE II.1 INDEPENDENT STATE PLANNING AND FORECASTING ACTIVITIES

STATE	INDEPENDENT FORECASTING AGENCIES	FREQUENCY OF FORECASTS ?	TIMEFRAME(S) OF FORECASTS ?	ELEMENTS INCLUDED IN STATE PLAN ?
MONTANA	DNR	during certification only	20 years	NA
NEBRASKA				
NEVADA	PUC; PRB	every 2 to 5 years	20 years	intrastate supply and demand interstate supply and demand other sources of power needs/sources of generating capacity transmission capacity needs
NEW HAMPSHIRE	none	*	*	*
NEW JERSEY	DCED; DEPC	every 2 to 5 years	15 years	intrastate supply and demand other sources of power needs/sources of generating capacity
NEW MEXICO	none	*	*	*
NEW YORK	Energy Office	less than every 2 years	16 years	intrastate supply and demand
NORTH CAROLINA	PUC	every 2 to 5 years	15 years	intrastate supply and demand other sources of power needs/sources of generating capacity
NORTH DAKOTA	none	*	*	*
OHIO	PUC	less than every 2 years	5.10.15 years	intrastate demand
OKLAHOMA	PUC	every 2 to 5 years	10 years	intrastate supply and demand
OREGON	Energy Office	every 2 to 5 years	20 years	intrastate demand needs of new generating capacity
PENNSYLVANIA	PUC	less than every 2 years	20 years	intrastate supply and demand interstate supply and demand other sources of power needs/sources of generating capacity transmission capcity needs
RHODE ISLAND	Energy Office	less than every 2 years	15 years	intrastate supply and demand interstate supply and demand other sources of power needs/sources of generating capacity
SOUTH CAROLINA	none	*	*	*

* Question is not applicable since no forecasts are performed by state.

TABLE II.1 INDEPENDENT STATE PLANNING AND FORECASTING ACTIVITIES

STATE	INDEPENDENT FORECASTING AGENCIES	FREQUENCY OF FORECASTS ?	TIMEFRAME(S) OF FORECASTS ?	ELEMENTS INCLUDED IN STATE PLAN ?
SOUTH DAKOTA	none	*	*	*
TENNESSEE	none	*	*	*
TEXAS	PUC	less than every 2 years	10 years	intrastate supply and demand interstate supply and demand other sources of power needs/sources of generating capacity
UTAH	PUC	less than every 2 years	20 years 25 years	intrastate demand needs of generating capacity
VERMONT	DPS	every 2 to 5 years	20 years	intrastate supply and demand interstate supply and demand other sources of power needs/sources of generating capacity transmission capacity needs
VIRGINIA	none	*	*	*
WASHINGTON	none	*	*	*
WEST VIRGINIA	PUC	less than every 2 years	10 years	intrastate supply and demand
WISCONSIN	PUC; Energy Office	every 2 to 5 years	20 years	intrastate supply and demand interstate supply and demand other sources of power needs/sources of generating capacity transmission capacity needs
WYOMING	none	*	*	*

* Question is not applicable since no forecasts are performed by state.

TABLE II.1 INDEPENDENT STATE PLANNING AND FORECASTING ACTIVITIES

STATE	PLANS INCLUDE TRANSMISSION CAPACITY REGARDING ?	PLANS USED IN CERTIFICATION AND SITING OF NEW GENERATING PLANT ?	RESULTS USED IN CERTIFICATION AND SITING OF NEW TRANSMISSION PLANT ?	RESULTS USED IN RATEMAKING PROCESS ?	STATE INVOLVED IN EXTRA-STATE PLANNING PROCESS WITH ?
ALABAMA	existing supply and demand	required		usually considered	regional planning authority
ALASKA	anticipated supply and demand				
ARIZONA	*	*	*	*	no
ARKANSAS	*	*	*	*	no
CALIFORNIA	anticipated supply and demand	required	certification only	required	regional planning authority utilities
COLORADO					
CONNECTICUT					
DELAWARE	*	*	*	*	no
DISTRICT OF COLUMBIA					no
FLORIDA	anticipated supply and demand	required	required	required	other states utilities
GEORGIA	*	*	*	*	no
HAWAII	*	*	*	*	no
IDAHO	anticipated supply and demand				regional planning authority
ILLINOIS		soon to be required	soon to be required	soon to be required	no

* Question is not applicable since no forecasts are performed by state.

TABLE II.1 INDEPENDENT STATE PLANNING AND FORECASTING ACTIVITIES

STATE	PLANS INCLUDE TRANSMISSION CAPACITY REGARDING ?	PLANS USED IN CERTIFICATION AND SITING OF NEW GENERATING PLANT ?	RESULTS USED IN CERTIFICATION AND SITING OF NEW TRANSMISSION PLANT ?	RESULTS USED IN RATEMAKING PROCESS ?	STATE INVOLVED IN EXTRA-STATE PLANNING PROCESS WITH ?
INDIANA	NA	required			no
IOWA	*	*	*	*	no
KANSAS					no
KENTUCKY	*	*	*	*	no
LOUISIANA					
MAINE		required	required	required	other states utilities
MARYLAND					no
MASSACHUSETTS	anticipated supply and demand				other states New Eng. Power Pool utilities
MICHIGAN	NA	NA	NA	NA	in regard to specific proceedings
MINNESOTA	anticipated supply and demand	usually considered	usually considered		other states
MISSISSIPPI					
MISSOURI	*	*	*	*	no

* Question is not applicable since no forecasts are performed by state.

TABLE II.1 INDEPENDENT STATE PLANNING AND FORECASTING ACTIVITIES

STATE	PLANS INCLUDE TRANSMISSION CAPACITY REGARDING ?	PLANS USED IN CERTIFICATION AND SITING OF NEW GENERATING PLANT ?	RESULTS USED IN CERTIFICATION AND SITING OF NEW TRANSMISSION PLANT ?	RESULTS USED IN RATEMAKING PROCESS ?	STATE INVOLVED IN EXTRA-STATE PLANNING PROCESS WITH ?
MONTANA	NA	NA	NA	NA	other states
NEBRASKA					
NEVADA	anticipated supply and demand existing supply and demand	required	required	required	regional planning authority
NEW HAMPSHIRE	*	*	*	*	
NEW JERSEY	anticipated supply and demand	required	usually considered	usually considered	no
NEW MEXICO	*	*	*	*	no
NEW YORK	anticipated supply and demand existing supply and demand	required	required		utilities
NORTH CAROLINA		required			regional planning authority
NORTH DAKOTA	*	*	*	*	no
OHIO	NA	NA	NA	NA	utilities
OKLAHOMA					no
OREGON		required	required		regional planning authority
PENNSYLVANIA	anticipated supply and demand	usually considered	required	required	no
RHODE ISLAND	anticipated supply and demand	required	required	usually considered	other states regional planning authority utilities
SOUTH CAROLINA	*	*	*	*	no

* Question is not applicable since no forecasts are performed by state.

TABLE II.1 INDEPENDENT STATE PLANNING AND FORECASTING ACTIVITIES

STATE	PLANS INCLUDE TRANSMISSION CAPACITY REGARDING ?	PLANS USED IN CERTIFICATION AND SITING OF NEW GENERATING PLANT ?	RESULTS USED IN CERTIFICATION AND SITING OF NEW TRANSMISSION PLANT ?	RESULTS USED IN RATEMAKING PROCESS ?	STATE INVOLVED IN EXTRA-STATE PLANNING PROCESS WITH ?
SOUTH DAKOTA	*	*	*	*	no
TENNESSEE	*	*	*	*	no
TEXAS	NA	required			no
UTAH	NA	usually considered	certification only		no
VERMONT	anticipated supply and demand	required	required		other states
VIRGINIA	*	*	*	*	utilities
WASHINGTON	*	*	*	*	
WEST VIRGINIA		usually considered	usually considered	usually considered	regional planning authority utilities
WISCONSIN	anticipated supply and demand	required	required	usually considered	no
WYOMING	*	*	*	*	other states

* Question is not applicable since no forecasts are performed by state.

SUMMARY REPORT

TABLE 11.2 UTILITY PLANNING AND FORECASTING ACTIVITIES

PLANS REQUIRED FOR CERTIFICATION AND SITING OF GENERATION FACILITIES?	
Yes	32
No	5
No Response	14

PLAN REQUIRED FOR GENERATION RELATED RATE CASE?	
Yes	27
No	10
No Response	14

PLAN REQUIRED FOR CERTIFICATION AND SITING OF TRANS. FACILITIES?	
Yes	25
No	10
Siting Only	1
No Response	15

PLAN REQUIRED FOR TRANSMISSION RELATED RATE CASE?	
Yes	17
No	16
No Response	18

UTILITY PLANS INCLUDE ANALYSIS OF ?	
Interstate Generating Capacity	29
Intrastate Sales/Purchases	34
Interstate Sales/Purchases	35
Need For Transmission Facilities	30
Least Cost Power Alternatives	29
Transmission of Least Cost Power	23
Load Management	1
Conservation	1
No Response	17

PLANS SUBMITTED BY POWER POOL/ HOLDING CO. FOR WHAT ENTITY ?	
Entire System	3
Individual Utility	10
Both	12
Not Applicable	7
No Response	17

TABLE II.2 UTILITY PLANNING AND FORECASTING ACTIVITIES

STATE	PLANS REQUIRED FOR CERTIFICATION AND SITING OF GENERATION FACILITIES?	PLAN REQUIRED FOR GENERATION RELATED RATE CASE?	PLAN REQUIRED FOR CERTIFICATION AND SITING OF TRANS. FACILITIES?	PLAN REQUIRED FOR TRANSMISSION RELATED RATE CASE?	UTILITY PLANS INCLUDE ANALYSIS OF ?	PLANS SUBMITTED BY POWER POOL/ HOLDING CO. FOR WHAT ENTITY ?
ALABAMA	yes	yes	no	no	intrastate sales/purchases interstate sales/purchases	
ALASKA	no	yes	no	yes	inter-state generating capacity intrastate sales/purchases need for transmission facilities least cost power transmission of least cost power	
ARIZONA	yes		siting only		need for transmission facilities	individual utility
ARKANSAS					intrastate sales/purchases interstate sales/purchases	individual utility
CALIFORNIA	no	no	no	no	interstate generating capacity intrastate sales/purchases interstate sales/purchases need for transmission facilities least cost power transmission of least cost power	entire system individual utility
COLORADO						
CONNECTICUT						
DELAWARE		yes				
DISTRICT OF COLUMBIA					interstate generating capacity interstate sales/purchases need for transmission facilities least cost power transmission of least cost power	
FLORIDA	yes	yes	yes	yes	interstate generating capacity intrastate sales/purchases interstate sales/purchases need for transmission facilities least cost power transmission of least cost power load management conservation	entire system

TABLE II.2   UTILITY PLANNING AND FORECASTING ACTIVITIES

STATE	PLANS REQUIRED FOR CERTIFICATION AND SITING OF GENERATION FACILITIES?	PLAN REQUIRED FOR GENERATION RELATED RATE CASE?	PLAN REQUIRED FOR CERTIFICATION AND SITING OF TRANS. FACILITIES?	PLAN REQUIRED FOR TRANSMISSION RELATED RATE CASE?	UTILITY PLANS INCLUDE ANALYSIS OF ?	PLANS SUBMITTED BY POWER POOL/ HOLDING CO. FOR WHAT ENTITY ?
GEORGIA		yes		yes	interstate generating capacity intrastate sales/purchases interstate sales/purchases	entire system individual utility
HAWAII	yes		yes			
IDAHO	yes	no			interstate generating capacity intrastate sales/purchases interstate sales/purchases	
ILLINOIS	yes	yes	yes	yes	interstate generating capacity interstate sales/purchases need for transmission facilities least cost power transmission of least cost power	
INDIANA	yes	yes	no	no	intrastate sales/purchases interstate sales/purchases least cost power	individual utility
IOWA	yes	yes	no	no	intrastate sales/purchases least cost power	entire system individual utility
KANSAS	yes	yes	yes	yes	interstate generating capacity intrastate sales/purchases interstate sales/purchases need for transmission facilities least cost power transmission of least cost power	entire system individual utility
KENTUCKY	yes	yes	no	yes	interstate generating capacity intrastate sales/purchases interstate sales/purchases need for transmission facilities least cost power transmission of least cost power	individual utility

TABLE II.2 UTILITY PLANNING AND FORECASTING ACTIVITIES

STATE	PLANS REQUIRED FOR CERTIFICATION AND SITING OF GENERATION FACILITIES?	PLAN REQUIRED FOR GENERATION RELATED RATE CASE?	PLAN REQUIRED FOR CERTIFICATION AND SITING OF TRANS. FACILITIES?	PLAN REQUIRED FOR TRANSMISSION RELATED RATE CASE?	UTILITY PLANS INCLUDE ANALYSIS OF ?	PLANS SUBMITTED BY POWER POOL/ HOLDING CO. FOR WHAT ENTITY ?
LOUISIANA						
MAINE	yes	yes	yes	yes	intrastate sales/purchases interstate sales/purchases need for transmission facilities	entire system individual utility
MARYLAND	yes	yes	yes	yes	interstate generating capacity intrastate sales/purchases interstate sales/purchases need for transmission facilities least cost power transmission of least cost power	entire system individual utility
MASSACHUSETTS	yes	yes	yes	yes	intrastate sales/purchases interstate sales/purchases need for transmission facilities least cost power transmission of least cost power	entire system individual utility
MICHIGAN		yes				NA
MINNESOTA	yes	yes	yes	yes	interstate generating capacity intrastate sales/purchases interstate sales/purchases need for transmission facilities least cost power transmission of least cost power	
MISSISSIPPI						
MISSOURI	yes	yes	yes	yes	intrastate sales/purchases interstate sales/purchases need for transmission facilities least cost power transmission of least cost power	entire system
MONTANA	yes	yes	yes	yes	interstate generating capacity intrastate sales/purchases interstate sales/purchases	NA

TABLE II.2 UTILITY PLANNING AND FORECASTING ACTIVITIES

STATE	PLANS REQUIRED FOR CERTIFICATION AND SITING OF GENERATION FACILITIES?	PLAN REQUIRED FOR GENERATION RELATED RATE CASE?	PLAN REQUIRED FOR CERTIFICATION AND SITING OF TRANS. FACILITIES?	PLAN REQUIRED FOR TRANSMISSION RELATED RATE CASE?	UTILITY PLANS INCLUDE ANALYSIS OF ?	PLANS SUBMITTED BY POWER POOL/ HOLDING CO. FOR WHAT ENTITY ?
NEBRASKA						
NEVADA	yes	yes	yes	no	interstate generating capacity intrastate sales/purchases interstate sales/purchases need for transmission facilities least cost power transmission of least cost power	NA
NEW HAMPSHIRE	yes		yes		interstate generating capacity intrastate sales/purchases interstate sales/purchases need for transmission facilities least cost power transmission of least cost power	individual utility
NEW JERSEY	yes	yes	yes	yes	interstate generating capacity intrastate sales/purchases interstate sales/purchases need for transmission facilities least cost power transmission of least cost power	entire system individual utility
NEW MEXICO						NA
NEW YORK	yes		yes		interstate generating capacity intrastate sales/purchases interstate sales/purchases need for transmission facilities	
NORTH CAROLINA	yes	no	no	no	least cost power	
NORTH DAKOTA	yes	no	yes	no	interstate generating capacity intrastate sales/purchases interstate sales/purchases need for transmission facilities least cost power transmission of least cost power	

TABLE II.2 UTILITY PLANNING AND FORECASTING ACTIVITIES

STATE	PLANS REQUIRED FOR CERTIFICATION AND SITING OF GENERATION FACILITIES?	PLAN REQUIRED FOR GENERATION RELATED RATE CASE?	PLAN REQUIRED FOR CERTIFICATION AND SITING OF TRANS. FACILITIES?	PLAN REQUIRED FOR TRANSMISSION RELATED RATE CASE?	UTILITY PLANS INCLUDE ANALYSIS OF ?	PLANS SUBMITTED BY POWER POOL/ HOLDING CO. FOR WHAT ENTITY ?
OHIO	no	no	no	no	intrastate sales/purchases interstate sales/purchases need for transmission facilities	entire system individual utility
OKLAHOMA		no		no	intrastate sales/purchases interstate sales/purchases need for transmission facilities least cost power transmission of least cost power	individual utility
OREGON	yes	yes	yes	no	interstate generating capacity intrastate sales/purchases interstate sales/purchases need for transmission facilities least cost power transmission of least cost power	individual utility
PENNSYLVANIA	yes	yes	yes	yes	need for transmission facilities least cost power transmission of least cost power	entire system individual utility
RHODE ISLAND	yes	yes	yes	yes	interstate generating capacity intrastate sales/purchases interstate sales/purchases need for transmission facilities least cost power transmission of least cost power	entire system
SOUTH CAROLINA	no	yes	no	no	interstate generating capacity intrastate sales/purchases interstate sales/purchases need for transmission facilities	individual utility
SOUTH DAKOTA	yes	yes	yes	yes	interstate generating capacity intrastate sales/purchases interstate sales/purchases need for transmission facilities least cost power transmission of least cost power	

TABLE II.2 UTILITY PLANNING AND FORECASTING ACTIVITIES

STATE	PLANS REQUIRED FOR CERTIFICATION AND SITING OF GENERATION FACILITIES?	PLAN REQUIRED FOR GENERATION RELATED RATE CASE?	PLAN REQUIRED FOR CERTIFICATION AND SITING OF TRANS. FACILITIES?	PLAN REQUIRED FOR TRANSMISSION RELATED RATE CASE?	UTILITY PLANS INCLUDE ANALYSIS OF ?	PLANS SUBMITTED BY POWER POOL/ HOLDING CO. FOR WHAT ENTITY ?
TENNESSEE	no	no	no	no	interstate purchases need for transmission facilities least cost power	NA
TEXAS	yes	yes	yes	no	interstate generating capacity intrastate sales/purchases interstate sales/purchases need for transmission facilities least cost power transmission of least cost power	individual utility
UTAH	yes		yes		intrastate sales/purchases interstate sales/purchases	NA
VERMONT	yes	yes	yes	yes		NA
VIRGINIA		yes			intrastate sales/purchases interstate sales/purchases least cost power	individual utility
WASHINGTON						
WEST VIRGINIA	yes	no	yes	no	intrastate sales/purchases interstate sales/purchases need for transmission facilities least cost power transmission of least cost power	entire system individual utility
WISCONSIN	yes	no	yes	no	interstate generating capacity intrastate sales/purchases interstate sales/purchases need for transmission facilities least cost power transmission of least cost power	entire system individual utility
WYOMING	yes	no	yes	no	interstate generating capacity intrastate sales/purchases interstate sales/purchases need for transmission facilities least cost power transmission of least cost power	

TABLE II.3 STATE OVERSIGHT OF UTILITY FORECASTS

ACCESS TO POWER POOL/HOLDING CO. FORECASTS OF TRANSMISSION NEEDS?	
Yes	34
No	7
Not Applicable	1
No Response	7

ACCESS TO POWER POOL/HOLDING CO. FORECASTS OF NEEDS IN STATE?	
Yes	22
No	4
Power Pool Only	1
Holding Co. Only	1
Not Applicable	5
No Response	18

RECIEVING AGENCIES FOR CAPACITY/ INVESTMENT PLANS AND FORECASTS?	
PUC	43
Energy Office	6
Other	6
Not Applicable	1
No Response	6

DO THESE AGENCIES EVALUATE UTILITY PLANS?	
Yes	39
No	5
For New Gen. Only	1
Not Applicable	0
No Response	6

TABLE II.3 STATE OVERSIGHT OF UTILITY FORECASTS

STATE	ACCESS TO POWER POOL/HOLDING CO. FORECASTS OF TRANSMISSION NEEDS?	ACCESS TO POWER POOL/HOLDING CO. FORECASTS OF NEEDS IN STATE?	RECIEVING AGENCIES FOR CAPACITY/ INVESTMENT PLANS AND FORECASTS?	DO THESE AGENCIES EVALUATE UTILITY PLANS?
ALABAMA	yes		PUC	if involving new generation
ALASKA	yes		PUC	no
ARIZONA	yes		PUC	yes
ARKANSAS	no	yes	PUC	yes
CALIFORNIA	yes	yes	Energy Commission	yes
COLORADO				
CONNECTICUT				
DELAWARE	no		PUC; plans not required	yes
DISTRICT OF COLUMBIA	yes		PUC	yes
FLORIDA	yes	yes	PUC; Dept. Community Affairs	yes
GEORGIA	yes	yes	PUC; plans not required	yes
HAWAII			PUC	yes
IDAHO			PUC	no
ILLINOIS	no	power pool only	PUC; DOE; DNR	yes
INDIANA	yes	yes	PUC	yes
IOWA	yes	no	PUC	yes
KANSAS	yes	yes	PUC	yes
KENTUCKY	yes	yes	PUC	yes
LOUISIANA				
MAINE	yes		PUC	yes
MARYLAND	no	holding co. only	PUC	yes
MASSACHUSETTS	yes	yes	PUC	yes
MICHIGAN	no		PUC	no
MINNESOTA	yes	yes	PUC	yes
MISSISSIPPI				
MISSOURI	yes	yes	PUC	yes

TABLE II.3 STATE OVERSIGHT OF UTILITY FORECASTS

STATE	ACCESS TO POWER POOL/HOLDING CO. FORECASTS OF TRANSMISSION NEEDS?	ACCESS TO POWER POOL/HOLDING CO. FORECASTS OF NEEDS IN STATE?	RECIEVING AGENCIES FOR CAPACITY/ INVESTMENT PLANS AND FORECASTS?	DO THESE AGENCIES EVALUATE UTILITY PLANS?
MONTANA	yes	yes	PUC	yes
NEBRASKA				
NEVADA	yes	NA	PUC; GOCS	yes
NEW HAMPSHIRE	yes	yes	PUC	yes
NEW JERSEY	yes	yes	PUC; Energy Office	yes
NEW MEXICO	yes	NA	PUC	yes
NEW YORK	yes		PUC; Energy Office	yes
NORTH CAROLINA	no	no	PUC	yes
NORTH DAKOTA	yes		PUC	yes
OHIO	yes	yes	PUC	yes
OKLAHOMA		no	PUC	yes
OREGON	no	yes	PUC; Energy Office; EFSB	yes
PENNSYLVANIA	yes	yes	PUC	yes
RHODE ISLAND	yes	yes	PUC; Energy Office	yes
SOUTH CAROLINA	yes	NA	PUC	yes
SOUTH DAKOTA	yes	NA	PUC	yes
TENNESSEE	yes	yes	plans not required	no
TEXAS	yes	no	PUC	yes
UTAH	NA	NA	PUC	yes
VERMONT	yes	yes	PUC; DPS	yes
VIRGINIA	yes	yes	PUC	no
WASHINGTON				
WEST VIRGINIA	yes	yes	PUC	yes
WISCONSIN	yes	yes	PUC	yes
WYOMING	yes		PUC	yes

DRAFT

ELECTRIC UTILITY GENERATION AND TRANSMISSION PLANNING AND COORDINATION:

SUMMARY OF UTILITY RESPONSES TO A SURVEY BY THE NATIONAL GOVERNORS' ASSOCIATION TASK FORCE ON ELECTRICITY TRANSMISSION

JULY 1988

Note: This document was prepared by staff members of the Public Utilities Commission of the State of Ohio under contract with the U.S. Congress, Office of Technology Assessment, Washington, D.C. This document was prepared for reference purposes and is being distributed for review and comment only and should not otherwise be reproduced, referenced or quoted. The conclusions expressed in this paper are those of the authors and do not necessarily reflect the views of the Office of Technology Assessment, the Public Utilities Commission of Ohio, or the National Governors' Association Task Force on Electricity Transmission. This document has not been reviewed or approved by the Technology Assessment Board.

DATA SOURCES

The primary data source was a utility survey instrument designed by the PUCO staff. This survey consisted of both multiple choice and narrative questions. Questions 9, 10, 12, 13, 15 and 16 were structured such that the respondent chose one of several multiple-choice responses. Questions 2, 7, 11, 14, 17, 20, 21, 23 and 24 were structured such that the respondent chose one of several multiple-choice responses and also provided additional narrative. Question 3 was structured such that the respondent filled in blanks with a transmission line mileage number. Lastly, questions 1, 4, 5, 6, 8, 18, 19 and 22 were structured such that the respondent provided only a narrative. In order to facilitate data analysis, the survey responses were partially computerized. The multiple-choice parts of questions 2, 7, 9-17, 20, 21, 23 and 24 were numerically coded and input into the computerized data base. In addition the following were coded and input:

question 3: miles of transmission lines;
question 4: "yes" there exist major transmission lines under construction, or "no" there are none;
question 6: "yes" there are interconnections planned or under construction, or "no" there are none.

When coding the responses for questions 2, 4, 6 and 12, the following assumptions were made:

question 2: No narrative response is equivalent to "no";
question 4: No narrative response is equivalent to "no";
question 6: No narrative response is equivalent to "no";
question 12: The choices (a) to (e) are in order of decreasing frequency. If a respondent marked more than one of the multiple-choice responses, only the highest frequency response was chosen for data input.

In addition to data from the utility surveys, the computerized data base contains the following items for each respondent:

(1) The N.E.R.C. reliability region. This is a geographic variable identifying the region in which the utility service area is located. The value of this variable depends on the location of the utility, not whether it is a member of the reliability council.

(2) The type of utility. There are four possible types: investor owned (IOU), rural electric cooperative (REC), municipal (MUNI) and federal, state and district systems (OTHER). These four types and the utilities which comprise them are from "Electrical World, Directory of Electric Utilities, 1986-1987" published by McGraw-Hill.

(3) Generating capability. The value of this variable is total generating capability as of January 1, 1986 as given in "Electrical World, Directory of Electric Utilities, 1986-1987" published by McGraw-Hill.

(4) System peak (summer and winter). The value of this variable is as given in "Electrical World, Directory of Electric Utilities, 1986-1987" published by McGraw- Hill.

(5) A binary variable identifying whether the utility service area crosses state boundaries or not.

(6) A binary variable identifying whether the utility is a member of a power pool or not. The power pools used to determine the value of this variable are shown in Appendix Q-1.

MULTIPLE RESPONSES

Several questions on the survey refer to interactions with state regulatory bodies. To facilitate clarity, respondents were requested to fill out a separate survey schedule for each state under whose jurisdiction the respondent operated. These instructions resulted in 19 respondents returning multiple survey schedules. There are several methods of handling the multiple responses. For this project the following method was chosen.

First, the survey questions were split into two groups depending upon whether the question was judged to be dependent or independent of state jurisdiction. For example, question (2) "Do you have any generating units under construction?" was judged to be independent of state jurisdiction, while question (11) "Are you required by law or rule to prepare the forecast of: demand?, supply?, transmission?" was judged to be dependent on state jurisdiction. The "dependent" group consists of questions 11, 12, 14, 16(b), 17, 20(c), 20(d), 21 and 24. The "independent" group consists of questions 2, 3, 4, 6, 7, 9, 10, 13, 15, 16(except b), 20(except c and d) and 23. The remaining questions are not part of the computerized data base.

Second, for questions in the "dependent" group, all survey schedules were coded and entered into the computerized data base.

Third, for each respondent who returned multiple survey schedules, those schedules were reviewed for consistency for each question in the "independent" group. This review showed that in all but one case respondents did indeed answer the questions in the "independent" group consistently. This validated the choice of questions for the "independent" group.

Finally, for each respondent who returned multiple survey schedules, those schedules were replaced by a single survey schedule. For questions in the "independent" group, this new, smaller set of survey schedules was coded and entered into the computerized data base. As shown above, this resulted in no loss of data variability, but does result in a smaller data sample.

BACKGROUND INFORMATION FOR RESPONDENTS

A listing of the various utilities in the data base is given in Appendix Q-2. There are 87 IOUs, 30 RECs, 47 MUNIs and 22 of other types. Display Q-1 presents the distribution by utility type across the NERC regions; this information is also presented graphically in Figures Q-1 and Q-2. Display Q-2 and Display Q-3 present the distribution across utility types and NERC regions of several utility characteristics: whether building generation or transmission, size, reserve margin, and whether in a power pool or not. 34 of the utilities have a service area which crosses state boundaries; these utilities returned 83 survey schedules for the multiple states in which they operate.

DISPLAY Q-1

Number of Respondents by Type and NERC Region

Counting only single responses:

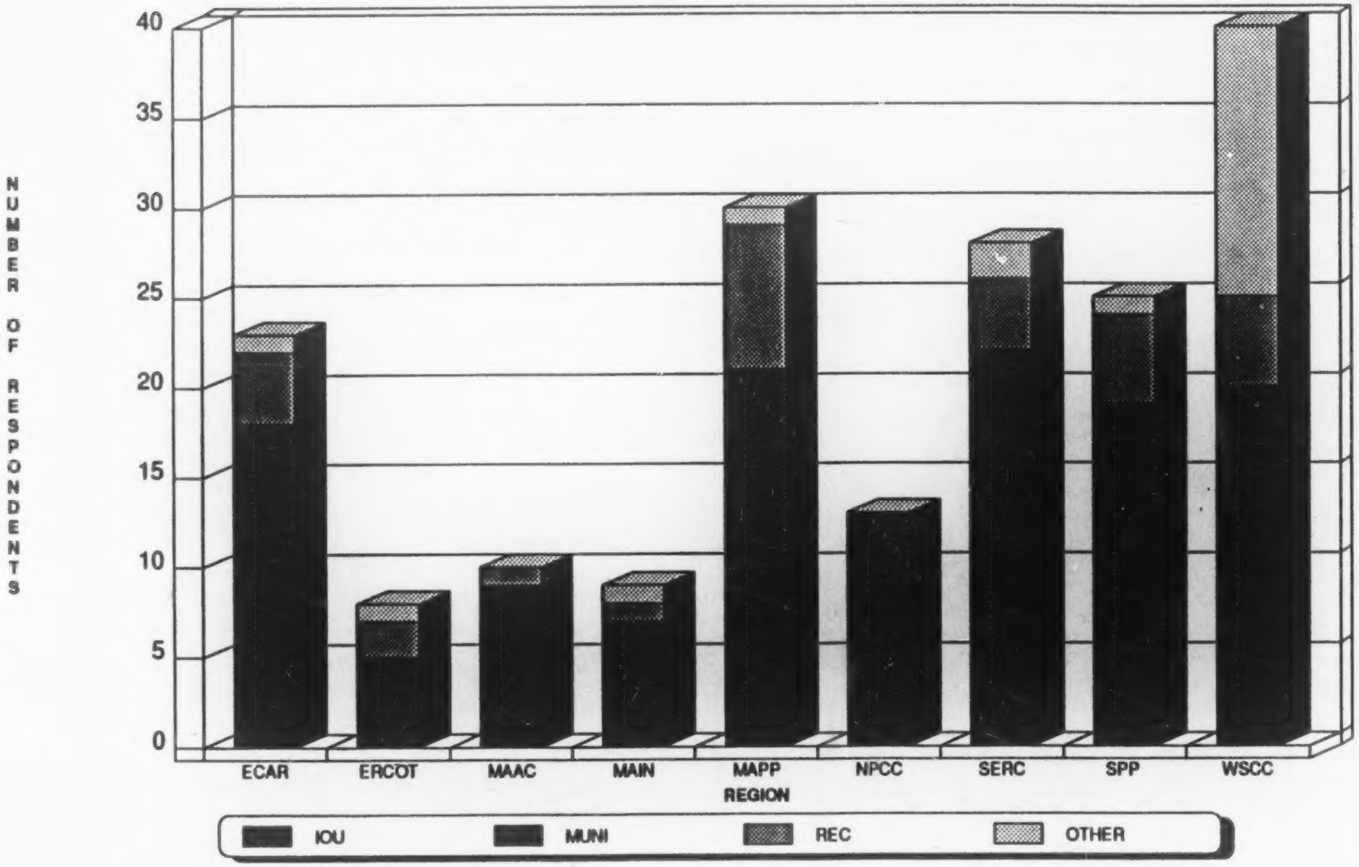
TYPE					
REGION	IOU	MUNI	REC	OTHER	Total
ECAR	12	6	4	1	23
ERCOT	2	3	2	1	8
MAAC	9	0	1	0	10
MAIN	7	0	1	1	9
MAPP	10	11	8	1	30
NPCC	9	4	0	0	13
SERC	11	11	4	2	28
SPP	14	5	5	1	25
WSCC	13	7	5	15	40
Total	87	47	30	22	186

Counting multiple state responses:

TYPE					
REGION	IOU	MUNI	REC	OTHER	Total
ECAR	24	6	4	1	35
ERCOT	2	3	2	3	10
MAAC	9	0	1	0	10
MAIN	9	0	1	1	11
MAPP	19	11	13	1	44
NPCC	13	4	0	0	17
SERC	12	11	4	2	29
SPP	23	5	5	1	34
WSCC	19	7	6	15	47
Total	130	47	36	24	237

FIGURE Q-1

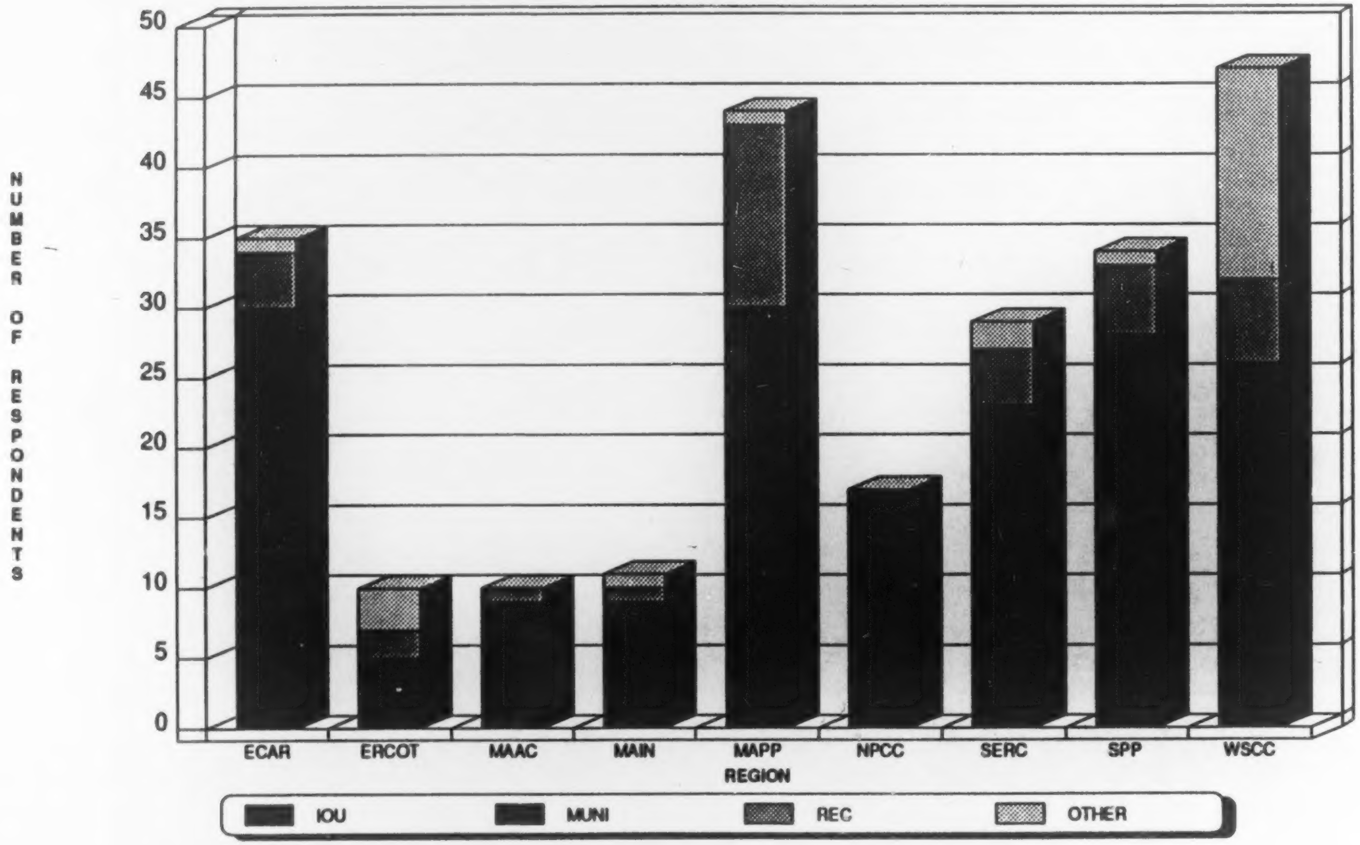
Number of Respondents by Type and NERC Region



NOTE: **Counting only single responses:**

FIGURE Q-2

Number of Respondents by Type and NERC Region



NOTE: Counting multiple state respnses:

DISPLAY Q-2

Utility Characteristics by Type and NERC Region

Counting only single responses:

TYPE	Building Generation	Not Building Generation	Building Trans.	Not Building Trans.	Trans. < 1000 Miles
IOU	35	52	46	41	25
MUNI	8	38	15	31	45
REC	4	26	12	18	14
OTHER	4	18	6	14	19
REGION					
ECAR	8	15	8	14	12
ERCOT	3	5	4	4	3
MAAC	5	5	6	4	4
MAIN	2	7	3	6	4
MAPP	3	26	12	18	17
NPCC	5	8	4	8	11
SERC	11	17	15	12	15
SPP	2	23	12	13	11
WSCC	12	28	15	25	26

TYPE	Trans. > 1000 Miles	Reserve Margin < 25%	Reserve Margin > 25%	In A Power Pool	Not In A Power Pool
IOU	62	38	46	56	31
MUNI	2	12	31	10	37
REC	16	12	14	9	21
OTHER	3	4	5	5	17
REGION					
ECAR	11	6	16	3	20
ERCOT	5	4	3	2	6
MAAC	6	6	4	9	1
MAIN	5	0	8	3	6
MAPP	13	10	18	22	8
NPCC	2	6	6	11	2
SERC	13	13	10	4	24
SPP	14	5	18	14	11
WSCC	14	16	13	12	28

DISPLAY Q-3

Utility Characteristics by Type and NERC Region

Counting multiple state responses:

TYPE	Building Generation	Not Building Generation	Building Trans.	Not Building Trans.	Trans. < 1000 Miles
IOU	51	79	81	49	30
MUNI	8	38	15	31	45
REC	4	32	15	21	14
OTHER	4	18	6	14	19
REGION					
ECAR	16	19	19	15	12
ERCOT	3	5	4	4	3
MAAC	5	5	6	4	4
MAIN	2	9	4	7	4
MAPP	6	37	20	24	21
NPCC	9	8	7	9	12
SERC	12	17	16	12	15
SPP	2	32	20	14	11
WSCC	12	35	21	26	26

TYPE	Trans. > 1000 Miles	Reserve Margin < 25%	Reserve Margin > 25%	In A Power Pool	Not In A Power Pool
IOU	100	62	64	89	41
MUNI	2	12	31	10	37
REC	22	12	20	15	21
OTHER	3	4	5	5	17
REGION					
ECAR	23	12	22	13	22
ERCOT	5	4	3	2	6
MAAC	6	6	4	9	1
MAIN	7	0	10	4	7
MAPP	23	18	24	33	11
NPCC	5	9	6	15	2
SERC	14	14	10	4	25
SPP	23	5	27	21	13
WSCC	21	22	14	18	29

The generating capacity, summer non-coincident peak, winter non-coincident peak and miles of transmission lines of 69 Kv and above for the respondents are shown in Display Q-4. This information is from "Electrical World, Directory of Electric Utilities, 1986-1987" and survey question 3. The summer generating capacity, winter generating capacity, summer non-coincident peak and winter non-coincident peak for the United States as a whole are shown in Display Q-5. This information is from the 1986 NERC report: "1986 Electricity Supply & Demand for 1986-1995". As can be seen from Display Q-4, the respondents have a non-coincident summer peak load of more than 318 gigawatts and have more than 428 gigawatts of generating capacity and 335,000 miles of transmission lines to serve that load. While Displays Q-4 and Q-5 are not strictly comparable, a review of these two Displays shows the respondents represent a substantial proportion of the electric generating capacity in the United States.

DISPLAY Q-4

REGION	CAPACITY (MW) (1)	SUMMER PEAK (MW) (1)	WINTER PEAK (MW) (1)	TRANSMISSION CAPACITY (MW) (2)
ECAR	76,019	53,399	56,627	53,711
ERCOT	26,267	21,939	18,422	22,167
MAAC	34,785	28,220	25,286	13,766
MAIN	38,183	23,742	21,605	16,245
MAPP	19,206	11,733	11,548	35,807
NPCC	23,038	18,937	16,726	7,491
SERC	94,743	80,304	84,373	55,578
SPP	41,783	25,269	20,184	63,937
WSCC	74,856	55,240	51,538	66,534
Total	428,880	318,783	306,309	335,236

1) "Electrical World Directory of Electric Utilities"
2) Survey question 3.

DISPLAY Q-5

REGION	SUMMER CAPACITY (MW) (1)	WINTER CAPACITY (MW) (1)	1986 SUMMER PEAK (MW) (1)	86/87 WINTER PEAK (MW) (1)
ECAR	96,452	99,240	68,356	67,355
ERCOT	43,414	44,971	38,957	31,574
MAAC	47,512	49,911	36,689	32,742
MAIN	45,334	47,182	35,752	28,953
MAPP	28,750	29,629	21,541	19,269
NPCC	52,396	54,586	40,820	39,003
SERC	133,167	137,828	100,818	99,450
SPP	65,201	65,685	47,298	34,829
WSCC	120,964	123,249	84,862	81,592
Total	633,190	652,281	475,093	434,767

1) "1986 Electricity Supply & Demand", N.E.R.C.

GENERATION AND TRANSMISSION CHARACTERISTICS

Questions 2, 3, and 4 asked for information on various generation and transmission characteristics. The utility responses for each question are discussed below.

Question 2

Question 2 asked respondents to list generating units under construction. 51 respondents reported 88 units under construction with a total capability of more 36,300 MW. Table Q-2 shows the distribution by NERC region.

TABLE Q-2

Question 2: Generating units under construction

NERC REGION	Number of Respondents	Number of Units	Total Size (MW)	Completion Date (Years) < 2	2 - 5	> 5
ECAR	10	14	5,382	6	8	0
ERCOT	3	8	5,844	3	3	2
MAAC	5	5	2,763	2	3	0
MAIN	2	2	2,070	2	0	0
MAPP	3	9	678	7	2	0
NPCC	8	7	4,010	4	1	0
SERC	11	21	12,994	10	9	2
SPP	2	2	116	1	1	0
WSCC	13	20	2,461	9	11	0
TOTAL	57	88	36,318	44	38	4

Question 3

Question 3 asked respondents to provide a breakdown of the transmission system line mileage by ranges of voltage levels: (1) 69Kv to 344Kv and (2) 345Kv and above. Table Q-3 summarizes this information by totals and by NERC region.

Table Q-3

Question 3: Transmission system breakdown by voltage levels

NERC REGION	Number of Respondents	Miles of Line 69-344 Kv	345-up Kv	Total Miles
ECAR	23	42,176	11,535	53,711
ERCOT	8	17,470	4,697	22,167
MAAC	10	11,533	2,233	13,766
MAIN	9	12,995	3,250	16,245
MAPP	30	29,733	6,074	35,807
NPCC	13	5,746	1,745	7,491
SERC	28	50,225	5,353	55,578
SPP	25	54,192	9,745	63,937
WSCC	40	56,208	10,326	66,534
TOTAL	186	280,278	54,958	335,236

Question 4

Question 4 asked respondents to list major transmission lines under construction. 89 respondents reported 166 such lines under construction, with 147 of size less than 345 Kv and 24 of size 345 Kv or larger. These projects total 3752 miles, including 1254 miles of 345 Kv and above. Table Q-4 shows the distribution by NERC region.

Table Q-4

Question 4: Major transmission lines under construction

NERC REGION	Number of Respondents	Number of Projects	Size (KV)		Total KV	Total Miles
			< 345	> 345		
ECAR	6	9	8	1	1,329	88
ERCOT	4	6	7	1	1,025	177
MAAC	11	8	10	1	2,271	145
MAIN	4	4	3	1	690	133
MAPP	10	15	14	1	2,116	262
NPCC	4	6	4	2	1,150	98
SERC	16	44	38	6	9,613	723
SPP	17	47	40	7	8,887	1,104
WSCC	17	27	23	4	5,086	1,022
TOTAL	89	166	147	24	32,167	3,752

TRENDS IN BULK POWER PURCHASES AND SALES

Question 7 was a two part question. Part A asked whether the respondent in the past five years had contracted to buy, for a limited time, capacity where the contract length exceeds one year; Part B asked whether the respondent in the past five years had contracted to sell, for a limited time, existing system capacity where the contract length exceeds one year.

Part A: Bulk Power Purchases.

The survey respondents reported a total of 193 contracts to buy power (with a length of more than one year) for a total of 30,806 MW. The lengths of these contracts range from one to forty years, with the majority of contract lengths being within the range six to eight years. "Economy" was listed as the rationale for 57% of these contracts. The other 43% listed rationales such as "capacity", "supply base load", "federal requirements", and "diversity". The start date of the contracts ranges from 1968 to 1994 with the majority ranging from 1981 to 1985.

A footnote to question 7A requested the respondents to indicate whether the contract was a "firm" or "non-firm" purchase. This was apparently not an appropriate way to present the request since this information was provided for only 4 of the 193 contracts listed by respondents.

Table Q-7A presents a summary of the responses for contracts to buy power. Respondents to this survey reported contracts totaling more than 30 gigawatts, with more than 40% of the total being shown by respondents in the SERC region.

TABLE Q-7A

Question 7A: Contracts to BUY power (length more than one year)

NERC REGION	Range of Contract Lengths (years)	No. of contracts with Rationale: "Economy"	No. of contracts with Rationale: "Other"	Range of Starting Years	Total Contract Amount (MW)
ECAR	6-10	0	3	1984-1985	188
ERCOT	2-15	0	9	1981-1987	1,759
MAAC	4-15	24	0	1980-1992	3,736
MAIN	2-10	1	1	1981-1984	213
MAPP	1.5-33	4	18	1979-1993	2,471
NPCC	1-40	20	12	1968-1986	2,356
SERC	1-40	25	11	1980-1994	12,757
SPP	1-25	1	15	1972-1991	2,287
WSCC	1-40	28	21	1968-1994	5,035
TOTAL	1-40	103	90	1968-1994	30,802

Respondents in the ECAR region reported 3 contracts to buy power for a total of 188 MW. The lengths of the contracts range from 6 to 10 years, with one for six years and one for 10 years. The third contract has no length indicated. Two contracts listed "capacity" and one listed "supply" as rationale. The starting dates are 1984 and 1985.

Respondents in the ERCOT region reported 9 contracts to buy power for a total of 1759 MW. The lengths of these contracts range from 2 to 15 years with two contracts each of 2 years, 10 years, and 12 years length. "Co-generation" was the rationale listed for seven contracts and "reliability" for two contracts. The starting date ranges from 1981 to 1987, with three contracts in 1981 and 1987.

Respondents in the MAAC region reported a total of 24 contracts to buy power for a total of 3736 MW, with 7 values unknown. The lengths of these contracts range from 4 to 15 years, with the majority of contract lengths being within the range 7 to 9 years. "Economy" was listed as the rationale for all contracts. The starting date of the contracts range from 1980 to 1992, with the majority starting 1982 to 1984.

Respondents in the MAIN region reported 2 contracts to buy power for a total of 213 MW. The lengths of the contracts are 2 and 10 years. "Economy" and "peaking" are the two rationales; and the starting dates are 1981 and 1984.

Respondents in the MAPP region reported 22 contracts to buy power for a total of 2471 MW. The lengths of the contracts range from 15 to 33 years with the majority of contract lengths being either 33 years or within the range 14 to 17 years. "Economy" was listed for 4 contracts as the rationale, with the other 18 listing "reliability", "federal requirement", "diversity" and "load serving" as the rationale. The starting dates range from 1979 to 1993, with no clear majority date established.

Respondents in the NPCC region reported 32 contracts to buy power for a total of 2356 MW, with a 7 values unknown. The lengths of the contracts range from 1 to 40 years, with no clear majority established. "Economy" was listed as the rationale for 20 contracts, with "reliability", "capacity", "PURPA", and "generation mix" as rationale for the other 12 contracts. The starting dates for the contracts range from 1968 to 1986, with the majority from 1982 to 1985.

Respondents in the SERC region reported 36 contracts to buy power for a total of 12 757 MW, with 3 values unknown. The lengths of the contracts range from 1 to 40 years, with the majority of contract lengths being within the range 3 to 12 years. "Economy" was listed for 25 contracts as the rationale; and "reliability", "system load", "peaking", and "replacement" were listed as the rationale for 11 contracts. The starting dates range from 1980 to 1994 with the majority starting 1983 to 1987.

Respondents in the SPP region reported 16 contracts to buy power for a total of 2287 MW, with 1 value unknown. The lengths of the contracts range from 1 to 25 years, with the majority of contract lengths being 1 year. "Economy" was listed as rationale for 1 contract, and 15 contracts listed "reliability", "capacity", "buyback", "load", and "peaking" as the rationale. The starting dates range from 1972 to 1991, with no clear majority established.

Respondents in the WSCC region reported 49 contracts to buy power for a total of 5035 MW, with 7 values unknown. The lengths of these contracts range from 1 to 40 years, with no majority established. "Economy" was listed for 28 contracts as the rationale; and "reliability", "capacity", "partial requirements", and "availability" was listed as the rationale for 21 contracts. The starting dates of the contracts range from 1968 to 1994, with the majority being 1981 to 1986.

Part B: Bulk Power Sales.

The survey respondents reported a total of 239 contracts to sell power (with a length of more than one year) for a total of 24,890 MW. The lengths of these contracts ranges from one to forty years, with the most frequent contract length being six years. "Economy" was listed as the rationale for 49% of these contracts. The other 51% listed rationales such as "reliability", "capacity", "diversity", and "generation". The starting date of the contracts ranges from 1963 to 1993, with the majority ranging from 1985.

A footnote to question 7B requested the respondents to indicate whether the contract was a "firm" or "non-firm" sale. This was apparently not an appropriate way to present the request since this information was provided for only 24 of the 239 contracts listed by respondents.

Table Q-7B presents a summary of the responses for contracts to sell power. Respondents to this survey reported contracts totaling more than 24 gigawatts, with approximately 30% of the total being shown by respondents in the SERC region.

Respondents in the ECAR region reported 19 contracts to sell power for a total of 3605 MW. The lengths of the contracts range from 0.6 to 38 years, with two contracts each of one year and eight years. "Economy" was listed as the rationale in only 32% of the contracts, with other rationales being "sellback", "supply", "capacity" and "firm power". The starting dates range from 1963 to 1991, with the majority starting in 1985.

TABLE Q-7B

Question 7B: Contracts to SELL power (length more than one year)

NERC REGION	Range of Contract Lengths (years)	No. of contracts with Rational: "Economy"	No. of contracts with Rational: "Other"	Range of Starting Years	Total Contract Amount (MW)
ECAR	0.6-38	6	13	1963-1991	3,605
ERCOT	1-8	0	8	1980-1987	3,200
MAAC	3.5-8	11	0	1981-1986	1,300
MAIN	2-14	2	1	1981-1985	585
MAPP	1.5-29	12	10	1981-1993	1,905
NPCC	1-24	16	42	1979-1986	1,091
SERC	0.2-17	40	13	1970-1992	7,485
SPP	1.2-30	13	24	1972-1987	3,482
WSCC	1-40	16	12	1981-1989	2,238
TOTAL	0.2-40	116	123	1963-1993	24,891

Respondents in the ERCOT region reported 8 contracts to sell power for a total of 3200 MW. The lengths of these contracts range from one to 8 years, with the majority of contract lengths being one year. "Economy" was not listed as a rationale for any contract; the rationales given were "firm power", "profit", and "reliability". The starting dates of the contract range from 1980 to 1987, with the majority starting in 1985.

Respondents in the MAAC region reported a total of 11 contracts to sell power for a total of 1300 MW, with 9 values unknown. The lengths of these contracts range from 3.5 to 8 years, with the majority of contract lengths being 7 years. "Economy" was listed as the rationale for all contracts. The starting dates of the contracts range from 1981 to 1985, with the majority starting in 1984.

Respondents in the MAIN region reported only 3 contracts to sell power for a total of 585 MW, with one value unknown. The lengths of the contracts range from 2 to 14 years. "Economy" was listed as the rationale for 2 contracts and "capacity" for the third. The starting dates are one in 1981 and two in 1985.

Respondents in the MAPP region reported 22 contracts to sell power for a total of 1905 MW. The lengths of the contracts range from 1.5 to 29 years, with the majority of contract lengths being 5 years. "Economy" was listed as the rationale for 55% of the contracts, with "generation", "participation", "firm power", and "diversity" being listed as rationale for the remainder. The starting dates range from 1981 to 1993, the majority starting in 1982.

Respondents in the NPCC region reported 58 contracts to sell power for a total of 1091 MW, with 22 values unknown. The lengths of the contracts range from one to 24 years, with the majority of contract lengths being 3 years. "Economy" was listed as the rationale for only 28% of the contracts; 72% listed "capacity" and "generating mix". The starting dates for the contracts range from 1979 to 1986, with the majority starting in 1981.

Respondents in the SERC region reported 53 contracts to sell power for a total of 7485 MW., with 2 values unknown. The lengths of the contracts range from 0.2 to 40 years, with the majority of contract lengths being 6 years. "Economy" was listed as the rationale for 75% of the contacts, with the remaining 25% listing "sellback", "reliability" and "firm power". The starting dates range from 1970 to 1992, with the majority starting in 1980.

Respondents in the SPP region reported 37 contracts to sell power for a total of 3481 MW., with 4 value unknown. The lengths of the contracts range from 1.2 to 30 years, with 5 contracts each of 4 years and 8 years length. "Economy" was listed as the rationale for 35% of the contracts, with the remaining 65% listing "reliability", "participation", "full requirement", "base", "firm power", and "capacity". The starting date ranges form 1972 to 1987, with the majority beginning in 1986.

Respondents in the WSCC region reported 28 contracts to sell power for a total of 2238 MW. The lengths of these contracts range from 1 to 40 years, with 4 contracts each of 6 years and 10 years length. "Economy" was listed as rationale for 57% of the contracts; the remaining 43% listed "firm power", "higher cost", "Palo Verde", "start-up", and "reliability". The starting date of the contracts range from 1981 to 1989, with the majority beginning in 1986.

PLANNING AND FORECASTING

Questions 9, 10, 13, 15, 16, 20, 21, and 23 asked for information about utility planning and forecasting. The utility responses for each question are summarized in the correspondingly numbered Tables below.

QUESTION 9.

Question 9 asked whether a forecast of electricity demand and supply is prepared and also asked about the regularity of such a forecast. The data shows every respondent prepares a forecast of electricity demand and supply -- the vast majority on a regular basis. 99% of IOU respondents prepare such forecasts on a regular basis, but so do more than 90% of each other utility type.

There are some differences across reliability regions. Most noticeable is that the three regions in which 100% of the respondents prepare forecasts of demand and supply on a regular basis comprise the Northeast quadrant of the United States (ECAR, MAAC AND NPCC).

In general, there are only minor differences among the various subsets; however, the data does show that 100% of the respondents who are building generation prepare forecasts of demand and supply on a regular basis.

QUESTION 10.

Question 10 asked whether a forecast of required transmission capacity is included in the supply plan. While most respondents do prepare such a forecast, a sizable minority (18%) do not. IOU and REC respondents prepare a forecast of required transmission capacity noticeably more often than MUNI and Other respondents.

When the various subsets are examined, the most noticeable difference is that only 1% of respondents with greater than 1000 miles of transmission lines do not prepare a transmission forecast, compared with 30% of the remaining respondents.

QUESTION 13.

Question 13 asked how many years into the future the forecasts of demand (question 13d), supply (question 13s), and transmission (question 13t) are regularly projected. In general the forecast of demand is projected somewhat farther into the future than is the forecast of supply, which in turn is projected noticeably farther into the future than is the forecast of transmission. The most frequent responses were 20 years for demand and supply and 10 years for transmission. The overall weighted averages are 16.8, 15.4, and 10.5 years, respectively.

With minor exceptions, the above observations apply to all utility types, NERC regions, and utility subsets. A review of the various subsets shows that membership in a power pool seems to make little difference; while the largest difference occurs when respondents are split between those having more than, and those having less than, 1000 miles of transmission lines.

QUESTION 15.

Question 15 asked whether generation planning routinely takes into account four items: (a) generation in neighboring utilities, (b) purchase/sale within the state, (c) purchase/sale outside the state, and (d) cogeneration and small power production. In general the responses were similar for all four items.

Overall, approximately 80% of the respondents answered "yes" to each item, except that approximately 90% answered "yes" to (b) routinely taking account of purchase/sale within the state. The responses show that IOU and REC respondents answered "yes" more often than MUNI and OTHER respondents. A review of the various subsets shows a respondent is more likely to answer "yes" if building generation or transmission, if having more than 1000 miles of transmission lines, if having a reserve margin less than 25%, and/or was a member of a power pool.

QUESTION 16.

Question 16 asked whether various topics were routinely taken into account in transmission planning. All eight topics received a majority of "yes" responses. The percentages ranged from a low of 55% for (b) "the transmission needs of your state" to approximately 80% for the topics: (a) "the regional power grid", (e)"to better use existing generating capacity", and (f) "to better use planned generating capacity".

When the responses were reviewed based on the type of utility, IOU respondents answered "yes" noticeably more often than the remaining three utility types with two exceptions. REC respondents, not surprisingly, answered "yes" more often for (c) "rural electric cooperatives and municipals in your service area". REC and MUNI respondents answered "yes" more often for (h) " the possibility for wheeling transactions".

For the various subsets, for each topic there is a higher "yes" response rate for respondents who are building transmission, who have more than 1000 miles of transmission lines, who have a reserve margin less then 25%, or who are members of a power pool. The one exception to the above observations is that respondents who are NOT building transmission answered "yes" more frequently to (h) "the possibility for wheeling transactions".

QUESTION 20.

Question 20 asked whether transmission planning (question 20t) and generation planning (question 20g) are coordinated on a regular basis with various entities. In general the responses indicate that generation planning is less frequently coordinated on a regular basis with the identified entities than is transmission planning. An exception is that Federal, State and District systems coordinated generation planning with state power authorities more frequently.

Other noticeable differences are as follows. IOU respondents coordinate generation and transmission planning on a regular basis with neighboring utilities more frequently than other respondents; MUNI respondents coordinate regularly much less frequently. Respondents in the WSCC region are the only ones to answer "yes" more often than "no" to coordinating generation and transmission planning with federal power authorities.

QUESTION 21.

Question 21 asked whether a service area crossing state boundaries has an effect on transmission planning. The respondents whose service area crosses state boundaries were, in total, about split on whether there is an effect on transmission planning. However, there were definite regional differences. Only in MAPP were the responses about evenly split. Other regions were one sided, with ECAR and MAIN showing "no" and with MAAC, NPCC, SERC, SPP, and WSCC showing "yes". ERCOT, of course, had no respondents who cross state boundaries.

When the respondents were divided based on whether transmission is under construction or not, those who are building were evenly split between "yes" and "no"; whereas 65% of those NOT building responded "yes".

QUESTION 23.

Question 23 asked for an assessment of seven potential rationales for building transmission lines. For ease of discussion of this analysis, "yes" and "possibly" are considered "positive" responses, while "unlikely" and "no" are considered "negative" responses.

Of the seven rationales, four received more positive than negative responses. Rationales (c) "enhanced service area reliability" and (d) "to purchase power for your own use" received more than 90% positive responses. The positive response rates for (c) and (d) were stable across all utility types, reliability regions, and subsets.

Rationales (e) "increased opportunities to sell your existing generation" and (g) "increased opportunities to sell power from your planned generation" received approximately 75% positive responses. For all utility types, reliability regions and subsets, the positive response rate was somewhat higher for (e) "EXISTING generation" than for (g) "PLANNED generation". For both these rationales, municipal respondents had a noticeably lower positive response rate, as did respondents in the MAAC, MAPP and NPCC reliability regions. In addition respondents in the NPCC reliability region had by far the highest rate of "no" responses. For the analyzed subsets the positive response rate is noticeably higher for respondents who are building generation or transmission or who have more than one thousand miles of transmission lines.

The remaining three rationales had noticeably lower positive response rates: rationale (f) "to purchase power from one neighboring utility to sell to another" had only 51% positive responses, while rationales (a) "to provide INTER-state transmission service" and (b) "to provide INTRA-state transmission service" had more negative responses than positive. Among these three rationales the responses seem to indicate a definite ranking: (a) more negative then (b), (b) more negative than (f). This ranking appears regardless of utility type, reliability region, or subset.

For these three rationales the assessment by IOU respondents was more positive than for other utility types. For reliability regions the positive response rate was noticeably higher for ERCOT [(b) and (f)], MAAC [(a) and (b)], MAIN [(f)] and SERC [(a), (b) and (f)]. On the other side, the negative response rate was noticeably higher for ECAR [(a), (b) and (f)] and WSCC [(a) and (b)]. ERCOT had a high negative response rate for (a) "to provide INTER-state transmission service" which is not a surprise considering its single state nature.

For three of the analyzed subsets there was a noticeable difference in the assessment of these latter three rationales. Respondents building generation or transmission responded more positively than those not building; and those with more than one thousand miles of transmission lines responded more positively than those with less.

TABLE Q-9

(9) Do you prepare forecasts of electricity demand and supply?

	COUNT	YES, on a regular basis	YES, but NOT on a regular basis	NO
ALL	186	95.2%	4.8%	0.0%
IOUs	87	98.9	1.1	0.0
RECs	30	90.0	10.0	0.0
MUNIs	47	93.6	6.4	0.0
OTHER *	22	90.9	9.1	0.0
ECAR	23	100.0	0.0	0.0
ERCOT	8	100.0	0.0	0.0
MAAC	10	100.0	0.0	0.0
MAIN	9	77.8	22.2	0.0
MAPP	30	96.7	3.3	0.0
NPCC	13	100.0	0.0	0.0
SERC	28	92.9	7.1	0.0
SPP	25	88.0	12.0	0.0
WSCC	40	97.5	2.5	0.0

* Federal, State, and District systems

TABLE Q-9

(9) Do you prepare forecasts of electricity demand and supply?

	COUNT	YES, on a regular basis	YES, but NOT on a regular basis	NO
Generation:				
building	51	100.0%	0.0%	0.0%
NOT building	135	93.3	6.7	0.0
Transmission:				
building	79	96.2	3.8	0.0
NOT building	107	94.4	5.6	0.0
Miles of transmission lines				
< 1000	103	93.2	6.8	0.0
> 1000	83	97.6	2.4	0.0
Reserve margin				
< 25%	67	98.5	1.5	0.0
> 25%	96	93.8	6.3	0.0
Member of a power pool?				
Yes	80	96.3	3.8	0.0
No	106	94.3	5.7	0.0

TABLE Q-10

(10) Is a forecast of required transmission capacity included in the supply plan?

	COUNT	YES	YES, but done independently of the supply plan	NO, although transmission forecast is prepared	NO, a transmission forecast is NOT prepared
ALL	186	30.6%	28.5%	23.1%	17.7%
IOUs	87	42.5	25.3	26.4	5.7
RECs	30	30.0	43.3	16.7	10.0
MUNIs	47	12.8	27.7	21.3	38.3
OTHER *	22	22.7	22.7	22.7	31.8
ECAR	23	43.5	30.4	8.7	17.4
ERCOT	8	37.5	25.0	37.5	0.0
MAAC	10	70.0	30.0	0.0	0.0
MAIN	9	11.1	33.3	33.3	22.2
MAPP	30	30.0	30.0	16.7	23.3
NPCC	13	53.8	15.4	0.0	30.8
SERC	28	25.0	32.1	32.1	10.7
SPP	25	12.0	44.0	32.0	12.0
WSCC	40	25.0	17.5	32.5	25.0

* Federal, State, and District systems

TABLE Q-10

(10) Is a forecast of required transmission capacity included in the supply plan?

	COUNT	YES	YES, but done independently of the supply plan	NO, although transmission forecast is prepared	NO, a transmission forecast is NOT prepared
Generation:					
building	51	45.1%	25.5%	23.5%	5.9%
NOT building	135	25.2	29.6	23.0	22.2
Transmission:					
building	79	29.1	31.6	30.4	8.9
NOT building	107	31.8	26.2	17.8	24.3
Miles of transmission lines					
< 1000	103	27.2	24.3	17.5	31.1
> 1000	83	34.9	33.7	30.1	1.2
Reserve margin					
< 25%	67	40.3	25.4	23.9	10.4
> 25%	96	27.1	31.3	21.9	19.8
Member of a power pool?					
Yes	80	37.5	27.5	18.8	16.3
No	106	25.5	29.2	26.4	18.9

TABLE Q-13d

(13d) How many years into the future do you regularly project DEMAND?

	COUNT	5 years	10 years	15 years	20 years	25 years	30 years	average (years)
ALL	186	5.9%	16.7%	16.1%	50.0%	5.9%	3.2%	16.8
IOUs	87	0.0	13.8	18.4	50.6	10.3	5.7	18.6
RECs	30	3.3	13.3	30.0	53.3	0.0	0.0	16.7
MUNIs	47	19.1	23.4	6.4	42.6	2.1	2.1	13.9
OTHER *	22	4.5	18.2	9.1	59.1	4.5	0.0	16.4
ECAR	23	4.3	17.4	13.0	47.8	13.0	0.0	16.7
ERCOT	8	12.5	37.5	0.0	25.0	12.5	12.5	16.3
MAAC	10	0.0	20.0	10.0	40.0	0.0	30.0	20.5
MAIN	9	0.0	22.2	11.1	55.6	0.0	11.1	18.3
MAPP	30	16.7	13.3	36.7	30.0	3.3	0.0	14.5
NPCC	13	15.4	7.7	23.1	38.5	7.7	0.0	14.6
SERC	28	3.6	7.1	10.7	64.3	10.7	3.6	19.1
SPP	25	0.0	28.0	24.0	40.0	4.0	0.0	15.4
WSCC	40	2.5	15.0	5.0	72.5	2.5	0.0	17.5

* Federal, State, and District systems

TABLE Q-13d

(13d) How many years into the future do you regularly project DEMAND?

	COUNT	5 years	10 years	15 years	20 years	25 years	30 years	average (years)
Generation:								
building	51	0.0%	13.7%	17.6%	51.0%	9.8%	7.8%	19.0
NOT building	135	8.1	17.8	15.6	49.6	4.4	1.5	16.0
Transmission:								
building	79	6.3	11.4	17.7	49.4	10.1	5.1	18.0
NOT building	107	5.6	20.6	15.0	50.5	2.8	1.9	15.9
Miles of transmission lines								
< 1000	103	9.7	21.4	11.7	49.5	1.9	1.9	15.3
> 1000	83	1.2	10.8	21.7	50.6	10.8	4.8	18.7
Reserve margin								
< 25%	67	4.5	7.5	16.4	64.2	1.5	4.5	18.0
> 25%	96	6.3	22.9	14.6	40.6	9.4	3.1	16.2
Member of a power pool?								
Yes	80	5.0	13.8	23.8	38.8	10.0	6.3	17.3
No	106	6.6	18.9	10.4	58.5	2.8	0.9	16.5

TABLE Q-13s

(13s) How many years into the future do you regularly project SUPPLY?

	COUNT	5 years	10 years	15 years	20 years	25 years	30 years	average (years)
ALL	186	4.3%	19.9%	16.1%	45.2%	3.8%	2.7%	15.4
IOUs	87	0.0	20.7	16.1	49.4	5.7	5.7	17.5
RECs	30	0.0	16.7	36.7	46.7	0.0	0.0	16.5
MUNIs	47	14.9	23.4	6.4	29.8	2.1	0.0	10.5
OTHER *	22	4.5	13.6	9.1	59.1	4.5	0.0	15.9
ECAR	23	4.3	21.7	17.4	56.5	0.0	0.0	16.3
ERCOT	8	0.0	50.0	12.5	25.0	12.5	0.0	15.0
MAAC	10	0.0	30.0	20.0	30.0	0.0	10.0	15.0
MAIN	9	0.0	22.2	11.1	55.6	0.0	11.1	18.3
MAPP	30	13.3	16.7	36.7	20.0	3.3	0.0	12.7
NPCC	13	7.7	15.4	23.1	23.1	7.7	7.7	14.2
SERC	28	3.6	10.7	3.6	53.6	10.7	7.1	17.3
SPP	25	0.0	32.0	24.0	40.0	0.0	0.0	14.8
WSCC	40	2.5	12.5	2.5	67.5	2.5	0.0	15.9

* Federal, State, and District systems

TABLE Q-13s

(13s) How many years into the future do you regularly project SUPPLY?

	COUNT	5 years	10 years	15 years	20 years	25 years	30 years	average (years)
Generation:								
building	51	0.0%	15.7%	19.6%	49.0%	5.9%	5.9%	17.5
NOT building	135	5.9	21.5	14.8	43.7	3.0	1.5	14.6
Transmission:								
building	79	5.1	13.9	20.3	48.1	6.3	3.8	17.0
NOT building	107	3.7	24.3	13.1	43.0	1.9	1.9	14.2
Miles of transmission lines								
< 1000	103	7.8	24.3	10.7	41.7	1.0	1.9	13.6
> 1000	83	0.0	14.5	22.9	49.4	7.2	3.6	17.7
Reserve margin								
< 25%	67	3.0	14.9	17.9	55.2	1.5	4.5	17.1
> 25%	96	4.2	24.0	14.6	38.5	5.2	2.1	14.4
Member of a power pool?								
Yes	80	3.8	20.0	25.0	32.5	7.5	5.0	15.8
No	106	4.7	19.8	9.4	54.7	0.9	0.9	15.1

TABLE Q-13t

(13t) How many years into the future do you regularly project TRANSMISSION?

	COUNT	5 years	10 years	15 years	20 years	25 years	30 years	average (years)
ALL	186	9.7%	39.2%	14.5%	18.3%	1.1%	0.0%	10.5
IOUs	87	6.9	49.4	21.8	16.1	1.1	0.0	12.1
RECs	30	10.0	40.0	20.0	23.3	0.0	0.0	12.2
MUNIs	47	12.8	27.7	2.1	19.1	2.1	0.0	8.1
OTHER *	22	13.6	22.7	4.5	18.2	0.0	0.0	7.3
ECAR	23	4.3	39.1	4.3	34.8	0.0	0.0	11.7
ERCOT	8	25.0	62.5	0.0	0.0	12.5	0.0	10.6
MAAC	10	0.0	20.0	70.0	0.0	0.0	0.0	12.5
MAIN	9	11.1	33.3	22.2	22.2	0.0	0.0	11.7
MAPP	30	13.3	30.0	26.7	13.3	0.0	0.0	10.3
NPCC	13	0.0	23.1	23.1	15.4	7.7	0.0	10.8
SERC	28	10.7	50.0	14.3	14.3	0.0	0.0	10.5
SPP	25	16.0	64.0	0.0	16.0	0.0	0.0	10.4
WSCC	40	7.5	30.0	5.0	25.0	0.0	0.0	9.1

* Federal, State, and District systems

TABLE Q-13t

(13t) How many years into the future do you regularly project TRANSMISSION?

	COUNT	5 years	10 years	15 years	20 years	25 years	30 years	average (years)
Generation:								
building	51	2.0%	56.9%	23.5%	11.8%	0.0%	0.0%	11.7
NOT building	135	12.6	32.6	11.1	20.7	1.5	0.0	10.1
Transmission:								
building	79	3.8	46.8	21.5	19.0	1.3	0.0	12.2
NOT building	107	14.0	33.6	9.3	17.8	0.9	0.0	9.3
Miles of transmission lines								
< 1000	103	12.6	28.2	6.8	22.3	1.0	0.0	9.2
> 1000	83	6.0	53.0	24.1	13.3	1.2	0.0	12.2
Reserve margin								
< 25%	67	10.4	44.8	23.9	14.9	0.0	0.0	11.6
> 25%	96	9.4	36.5	11.5	21.9	2.1	0.0	10.7
Member of a power pool?								
Yes	80	8.8	41.3	25.0	11.3	1.3	0.0	10.9
No	106	10.4	37.7	6.6	23.6	0.9	0.0	10.2

TABLE Q-15:a-b

(15:a-b) Does your generation planning routinely take into account:

	COUNT	existing or anticipated generation in neighboring utilities? Yes	existing or anticipated generation in neighboring utilities? No	purchase from or sales to other utilities in the state? Yes	purchase from or sales to other utilities in the state? No
ALL	186	82.3%	12.4%	88.7%	5.4%
IOUs	87	96.6	3.4	96.6	3.4
RECs	30	90.0	6.7	96.7	0.0
MUNIs	47	57.4	25.5	72.3	10.6
OTHER *	22	68.2	27.3	81.8	9.1
ECAR	23	78.3	17.4	91.3	4.3
ERCOT	8	75.0	25.0	100.0	0.0
MAAC	10	100.0	0.0	100.0	0.0
MAIN	9	100.0	0.0	100.0	0.0
MAPP	30	80.0	6.7	80.0	6.7
NPCC	13	84.6	0.0	84.6	0.0
SERC	28	85.7	7.1	85.7	7.1
SPP	25	80.0	20.0	96.0	4.0
WSCC	40	77.5	20.0	85.0	10.0

* Federal, State, and District systems

TABLE Q-15:a-b

(15:a-b) Does your generation planning routinely Take into account:

	COUNT	existing or anticipated generation in neighboring utilities?		purchase from or sales to other utilities in the state?	
		Yes	No	Yes	No
Generation:					
building	51	96.1%	3.9%	96.1%	3.9%
NOT building	135	77.0	15.6	85.9	5.9
Transmission:					
building	79	89.9	7.6	92.4	5.1
NOT building	107	76.6	15.9	86.0	5.6
Miles of transmission lines					
< 1000	103	70.9	19.4	81.6	7.8
> 1000	83	96.4	3.6	97.6	2.4
Reserve margin					
< 25%	67	94.0	4.5	95.5	3.0
> 25%	96	79.2	14.6	88.5	5.2
Member of a power pool?					
Yes	80	93.8	5.0	93.8	5.0
No	106	73.6	17.9	84.9	5.7

TABLE Q-15:c-d

(15:c-d) Does your generation planning routinely take into account:

	COUNT	purchase from or sales to other utilities outside the state?		cogeneration and small power production in your service area?	
		Yes	No	Yes	No
ALL	186	79.6%	14.0%	78.5%	15.6%
IOUs	87	97.7	2.3	95.4	4.6
RECs	30	86.7	10.0	73.3	23.3
MUNIs	47	46.8	31.9	55.3	25.5
OTHER *	22	68.2	27.3	68.2	27.3
ECAR	23	69.6	21.7	69.6	21.7
ERCOT	8	50.0	50.0	100.0	0.0
MAAC	10	100.0	0.0	100.0	0.0
MAIN	9	100.0	0.0	88.9	11.1
MAPP	30	70.0	13.3	73.3	13.3
NPCC	13	84.6	0.0	84.6	0.0
SERC	28	75.0	17.9	71.4	21.4
SPP	25	92.0	8.0	80.0	20.0
WSCC	40	82.5	15.0	77.5	20.0

* Federal, State, and District systems

TABLE Q-15:c-d

(15:c-d) Does your generation planning routinely take into account:

		purchase from or sales to other utilities outside the state?		cogeneration and small power production in your service area?	
	COUNT	Yes	No	Yes	No
Generation:					
building	51	92.2%	7.8%	90.2%	9.8%
NOT building	135	74.8	16.3	74.1	17.8
Transmission:					
building	79	88.6	7.6	86.1	11.4
NOT building	107	72.9	18.7	72.9	18.7
Miles of transmission lines					
< 1000	103	67.0	21.4	68.9	20.4
> 1000	83	95.2	4.8	90.4	9.6
Reserve margin					
< 25%	67	89.6	7.5	91.0	7.5
> 25%	96	78.1	14.6	72.9	19.8
Member of a power pool?					
Yes	80	92.5	6.3	87.5	11.3
No	106	69.8	19.8	71.7	18.9

TABLE Q-16:a-b

(16:a-b) Does your transmission planning routinely take into account:

		the regional power grid?			the transmission needs of your state as a whole?	
	COUNT	Yes	No	COUNT	Yes	No
ALL	186	80.6%	11.3%	235	54.9%	37.4%
IOUs	87	98.9	1.1	130	61.5	37.7
RECs	30	86.7	10.0	36	69.4	25.0
MUNIs	47	53.2	27.7	47	31.9	46.8
OTHER *	22	59.1	18.2	22	40.9	36.4
ECAR	23	69.6	13.0	35	40.0	45.7
ERCOT	8	100.0	0.0	8	100.0	0.0
MAAC	10	100.0	0.0	10	80.0	20.0
MAIN	9	77.8	11.1	11	63.6	27.3
MAPP	30	80.0	13.3	44	75.0	20.5
NPCC	13	76.9	7.7	17	64.7	17.6
SERC	28	75.0	17.9	29	55.2	37.9
SPP	25	88.0	12.0	34	23.5	76.5
WSCC	40	80.0	10.0	47	51.1	38.3

* Federal, State, and District systems

TABLE Q-16:a-b

(16:a-b) Does your transmission planning routinely take intc account:

		the regional power grid?			the transmission needs of your state as a whole?	
	COUNT	Yes	No	COUNT	Yes	No
Generation:						
building	51	94.1%	5.9%	67	79.1%	20.9%
NOT building	135	75.6	13.3	168	45.2	44.0
Transmission:						
building	79	91.1	7.6	117	64.1	35.0
NOT building	107	72.9	14.0	118	45.8	39.8
Miles of transmission lines						
< 1000	103	67.0	18.4	108	41.7	41.7
> 1000	83	97.6	2.4	127	66.1	33.9
Reserve margin						
< 25%	67	91.0	6.0	92	71.7	25.0
> 25%	96	79.2	13.5	120	47.5	45.8
Member of a power pool?						
Yes	80	92.5	3.8	119	63.0	33.6
No	106	71.7	17.0	116	46.6	41.4

TABLE Q-16:c-e

(16:c-e) Does your transmission planning routinely take into account:

	COUNT	rural electric cooperatives & municipalities in your service area?		cogenerators and small power producers in your service area?		the need for transmission facilities to better use EXISTING generating capacity?	
		Yes	No	Yes	No	Yes	No
ALL	186	73.1%	15.1%	64.5%	24.7%	79.0%	11.8%
IOUs	87	86.2	10.3	87.4	11.5	94.3	5.7
RECs	30	93.3	0.0	56.7	36.7	80.0	13.3
MUNIs	47	44.7	29.8	42.6	31.9	55.3	23.4
OTHER *	22	54.5	22.7	31.8	45.5	68.2	9.1
ECAR	23	60.9	17.4	60.9	17.4	78.3	4.3
ERCOT	8	*****	0.0	62.5	25.0	100.0	0.0
MAAC	10	80.0	10.0	100.0	0.0	100.0	0.0
MAIN	9	88.9	0.0	77.8	11.1	66.7	22.2
MAPP	30	83.3	6.7	63.3	30.0	70.0	23.3
NPCC	13	53.8	15.4	76.9	0.0	61.5	15.4
SERC	28	71.4	17.9	75.0	17.9	78.6	14.3
SPP	25	80.0	20.0	52.0	48.0	88.0	12.0
WSCC	40	65.0	22.5	52.5	32.5	80.0	7.5

* Federal, State, and District systems

TABLE Q-16:c-e

(16:c-e) Does your transmission planning routinely take into account:

		rural electric cooperatives & municipalities in your service area?		cogenerators and small power producers in your service area?		the need for transmission facilities to better use EXISTING generating capacity?	
	COUNT	Yes	No	Yes	No	Yes	No
Generation:							
building	51	84.3%	11.8%	86.3%	13.7%	92.2%	7.8%
NOT building	135	68.9	16.3	56.3	28.9	74.1	13.3
Transmission:							
building	79	87.3	10.1	75.9	21.5	92.4	6.3
NOT building	107	62.6	18.7	56.1	27.1	69.2	15.9
Miles of transmission lines							
< 1000	103	56.3	23.3	51.5	30.1	67.0	16.5
> 1000	83	94.0	4.8	80.7	18.1	94.0	6.0
Reserve margin							
< 25%	67	79.1	14.9	77.6	17.9	85.1	11.9
> 25%	96	71.9	16.7	61.5	28.1	80.2	11.5
Member of a power pool?							
Yes	80	80.0	11.3	76.3	18.8	85.0	10.0
No	106	67.9	17.9	55.7	29.2	74.5	13.2

TABLE Q-16:f-h

(16:f-h) Does your transmission planning routinely take into account:

		the need for transmission facilities to better use PLANNED generating capacity?		the possibility of using new transmission capacity to defer generating additions?		the possibility for wheeling transactions?	
	COUNT	Yes	No	Yes	No	Yes	No
ALL	186	80.6%	9.7%	74.7%	14.0%	65.6%	25.8%
IOUs	87	97.7	2.3	90.8	6.9	65.5	33.3
RECs	30	83.3	10.0	76.7	13.3	70.0	23.3
MUNIs	47	55.3	21.3	53.2	23.4	66.0	17.0
OTHER *	22	63.6	13.6	54.5	22.7	59.1	18.2
ECAR	23	73.9	8.7	69.6	8.7	39.1	43.5
ERCOT	8	100.0	0.0	87.5	0.0	87.5	12.5
MAAC	10	100.0	0.0	100.0	0.0	80.0	20.0
MAIN	9	77.8	11.1	66.7	22.2	66.7	22.2
MAPP	30	73.3	16.7	73.3	16.7	70.0	23.3
NPCC	13	69.2	7.7	53.8	15.4	84.6	0.0
SERC	28	75.0	17.9	75.0	17.9	60.7	32.1
SPP	25	96.0	4.0	88.0	12.0	60.0	40.0
WSCC	40	80.0	7.5	70.0	17.5	70.0	17.5

* Federal, State, and District systems

TABLE Q-16:f-h

(16:f-h) Does your transmission planning routinely take into account:

		the need for transmission facilities to better use PLANNED generating capacity?		the possibility of using new transmission capacity to defer generating additions?		the possibility for wheeling transactions?	
	COUNT	Yes	No	Yes	No	Yes	No
Generation:							
building	51	96.1%	3.9%	86.3%	11.8%	68.6%	31.4%
NOT building	135	74.8	11.9	70.4	14.8	64.4	23.7
Transmission:							
building	79	92.4	6.3	88.6	10.1	62.0	36.7
NOT building	107	72.0	12.1	64.5	16.8	68.2	17.8
Miles of transmission lines							
< 1000	103	68.0	14.6	60.2	20.4	65.0	19.4
> 1000	83	96.4	3.6	92.8	6.0	66.3	33.7
Reserve margin							
< 25%	67	92.5	4.5	83.6	10.4	70.1	25.4
> 25%	96	79.2	11.5	74.0	15.6	64.6	29.2
Member of a powUr pool?							
Yes	80	90.0	5.0	83.8	10.0	70.0	26.3
No	106	73.6	13.2	67.9	17.0	62.3	25.5

TABLE Q-20g:a-b

(20g:a-b) Is GENERATION planning coordinated on a regular basis with:

		members of a power pool?		neighboring utilities?	
	COUNT	Yes	No	Yes	No
ALL	186	59.1%	33.3%	72.6%	18.3%
IOUs	87	70.1	27.6	86.2	12.6
RECs	30	53.3	40.0	80.0	13.3
MUNIs	47	42.6	44.7	46.8	34.0
OTHER *	22	59.1	22.7	63.6	13.6
ECAR	23	26.1	69.6	69.6	26.1
ERCOT	8	37.5	50.0	62.5	25.0
MAAC	10	90.0	10.0	90.0	10.0
MAIN	9	55.6	44.4	77.8	22.2
MAPP	30	73.3	16.7	83.3	6.7
NPCC	13	84.6	0.0	69.2	7.7
SERC	28	39.3	46.4	64.3	25.0
SPP	25	64.0	36.0	72.0	28.0
WSCC	40	67.5	25.0	70.0	15.0

* Federal, State, and District systems

TABLE Q-20g:a-b

(20g:a-b) Is GENERATION planning coordinated on a regular basis with:

		members of a power pool?		neighboring utilities?	
	COUNT	Yes	No	Yes	No
Generation:					
building	51	52.9%	41.2%	80.4%	15.7%
NOT building	135	61.5	30.4	69.6	19.3
Transmission:					
building	79	59.5	35.4	72.2	22.8
NOT building	107	58.9	31.8	72.9	15.0
Miles of transmission lines					
< 1000	103	58.3	31.1	64.1	22.3
> 1000	83	60.2	36.1	83.1	13.3
Reserve margin					
< 25%	67	68.7	28.4	83.6	11.9
> 25%	96	56.3	36.5	70.8	20.8
Member of a power pool?					
Yes	80	95.0	5.0	88.8	8.8
No	106	32.1	54.7	60.4	25.5

TABLE Q-20g:c-d

(20g:c-d) Is GENERATION planning coordinated on a regular basis with:

	COUNT	state power authorities?		other state agencies?	
		Yes	No	Yes	No
ALL	235	30.6%	49.8%	31.5%	49.8%
IOUs	130	33.1	51.5	36.9	49.2
RECs	36	33.3	50.0	41.7	41.7
MUNIs	47	14.9	55.3	12.8	57.4
OTHER *	22	45.5	27.3	22.7	50.0
ECAR	35	22.9	65.7	31.4	60.0
ERCOT	8	25.0	50.0	12.5	62.5
MAAC	10	10.0	90.0	50.0	50.0
MAIN	11	18.2	63.6	45.5	54.5
MAPP	44	45.5	31.8	56.8	22.7
NPCC	17	35.3	35.3	35.3	29.4
SERC	29	34.5	44.8	24.1	55.2
SPP	34	5.9	64.7	0.0	67.6
WSCC	47	44.7	40.4	29.8	55.3

* Federal, State, and District systems

TABLE Q-20g:c-d

(20g:c-d) Is GENERATION planning coordinated on a regular basis with:

		state power authorities?		other state agencies?	
	COUNT	Yes	No	Yes	No
Generation:					
building	67	41.8%	46.3%	43.3%	49.3%
NOT building	168	26.2	51.2	26.8	50.0
Transmission:					
building	117	35.9	41.0	36.8	44.4
NOT building	118	25.4	58.5	26.3	55.1
Miles of transmission lines					
< 1000	108	25.0	52.8	26.9	50.9
> 1000	127	35.4	47.2	35.4	48.8
Reserve margin					
< 25%	92	46.7	41.3	44.6	42.4
> 25%	120	18.3	59.2	24.2	55.8
Member of a power pool?					
Yes	119	15.0	36.3	42.9	43.7
No	116	16.0	40.6	19.8	56.0

TABLE Q-20g:e-f

(20g:e-f) Is GENERATION planning coordinated on a regular basis with:

		federal power authorities?		other?	
	COUNT	Yes	No	Yes	No
ALL	186	22.6%	58.6%	15.6%	38.7%
IOUs	87	25.3	63.2	18.4	40.2
RECs	30	30.0	53.3	16.7	30.0
MUNIs	47	10.6	57.4	12.8	38.3
OTHER *	22	27.3	50.0	9.1	45.5
ECAR	23	4.3	87.0	17.4	56.5
ERCOT	~~8~~	0.0	62.5	0.0	62.5
MAAC	10	10.0	90.0	10.0	70.0
MAIN	9	0.0	88.9	22.2	55.6
MAPP	30	23.3	50.0	3.3	26.7
NPCC	13	15.4	30.8	7.7	7.7
SERC	28	25.0	50.0	14.3	35.7
SPP	25	24.0	68.0	24.0	52.0
WSCC	40	45.0	42.5	25.0	25.0

* Federal, State, and District systems

TABLE Q-20g:e-f

(20g:e-f) Is GENERATION planning coordinated on a regular basis with:

		federal power authorities?		other?	
	COUNT	Yes	No	Yes	No
Generation:					
building	51	25.5%	62.7%	17.6%	39.2%
NOT building	135	21.5	57.0	14.8	38.5
Transmission:					
building	79	34.2	48.1	20.3	26.6
NOT building	107	14.0	66.4	12.1	47.7
Miles of transmission lines					
< 1000	103	17.5	59.2	12.6	39.8
> 1000	83	28.9	57.8	19.3	37.3
Reserve margin					
< 25%	67	34.3	50.7	16.4	37.3
> 25%	96	11.5	68.8	14.6	40.6
Member of a power pool?					
Yes	80	30.0	55.0	15.0	36.3
No	106	17.0	61.3	16.0	40.6

TABLE Q-20t:a-b

(20t:a-b) Is TRANSMISSION planning coordinated on a regular basis with:

	COUNT	members of a power pool?		neighboring utilities?	
		Yes	No	Yes	No
ALL	186	65.1%	26.9%	80.1%	11.8%
IOUs	87	77.0	20.7	96.6	2.3
RECs	30	63.3	33.3	80.0	13.3
MUNIs	47	42.6	38.3	53.2	29.8
OTHER *	22	68.2	18.2	72.7	9.1
ECAR	23	26.1	65.2	78.3	17.4
ERCOT	8	50.0	37.5	87.5	0.0
MAAC	10	90.0	10.0	90.0	0.0
MAIN	9	55.6	44.4	88.9	11.1
MAPP	30	86.7	6.7	86.7	6.7
NPCC	13	69.2	0.0	61.5	7.7
SERC	28	42.9	42.9	78.6	14.3
SPP	25	80.0	16.0	80.0	20.0
WSCC	40	75.0	22.5	77.5	12.5

* Federal, State, and District systems

TABLE Q-20t:a-b

(20t:a-b) Is TRANSMISSION planning coordinated on a regular basis with:

		members of a power pool?		neighboring utilities?	
	COUNT	Yes	No	Yes	No
Generation:					
building	51	64.7%	31.4%	90.2%	5.9%
NOT building	135	65.2	25.2	76.3	14.1
Transmission:					
building	79	69.6	27.8	84.8	11.4
NOT building	107	61.7	26.2	76.6	12.1
Miles of transmission lines					
< 1000	103	61.2	27.2	67.0	20.4
> 1000	83	69.9	26.5	96.4	1.2
Reserve margin					
< 25%	67	71.6	23.9	86.6	6.0
> 25%	96	63.5	28.1	79.2	14.6
Member of a power pool?					
Yes	80	95.0	2.5	92.5	3.8
No	106	42.5	45.3	70.8	17.9

TABLE Q-20t:c-d

(20t:c-d) Is TRANSMISSION planning coordinated on a regular basis with:

	COUNT	state power authorities?		other state agencies?	
		Yes	No	Yes	No
ALL	235	31.9%	49.4%	31.5%	52.3%
IOUs	130	33.8	50.8	35.4	52.3
RECs	36	36.1	50.0	41.7	47.2
MUNIs	47	19.1	53.2	17.0	55.3
OTHER *	22	40.9	31.8	22.7	54.5
ECAR	35	22.9	62.9	31.4	60.0
ERCOT	8	50.0	25.0	25.0	50.0
MAAC	10	10.0	90.0	50.0	50.0
MAIN	11	18.2	63.6	27.3	72.7
MAPP	44	47.7	36.4	56.8	29.5
NPCC	17	29.4	41.2	29.4	35.3
SERC	29	34.5	48.3	24.1	55.2
SPP	34	20.6	47.1	0.0	67.6
WSCC	47	36.2	48.9	34.0	57.4

* Federal, State, and District systems

TABLE Q-20t:c-d

(20t:c-d) Is TRANSMISSION planning coordinated on a regular basis with:

		state power authorities?		other state agencies?	
	COUNT	Yes	No	Yes	No
Generation:					
building	67	43.3%	46.3%	43.3%	52.2%
NOT building	168	27.4	50.6	26.8	52.4
Transmission:					
building	117	39.3	40.2	38.5	46.2
NOT building	118	24.6	58.5	24.6	58.5
Miles of transmission lines					
< 1000	108	23.1	55.6	25.9	53.7
> 1000	127	39.4	44.1	36.2	51.2
Reserve margin					
< 25%	92	45.7	42.4	44.6	44.6
> 25%	120	20.8	57.5	22.5	60.0
Member of a power pool?					
Yes	119	38.7	45.4	41.2	46.2
No	116	25.0	53.4	21.6	58.6

TABLE Q-20t:e-f

(20t:e-f) Is TRANSMISSION planning coordinated on a regular basis with:

	COUNT	federal power authorities?		other?	
		Yes	No	Yes	No
ALL	186	26.9%	55.4%	16.1%	37.1%
IOUs	87	28.7	57.5	18.4	39.1
RECs	30	36.7	53.3	16.7	33.3
MUNIs	47	17.0	53.2	12.8	36.2
OTHER *	22	27.3	54.5	13.6	36.4
ECAR	23	4.3	82.6	26.1	47.8
ERCOT	8	0.0	62.5	12.5	50.0
MAAC	10	10.0	90.0	10.0	70.0
MAIN	9	0.0	88.9	11.1	66.7
MAPP	30	30.0	46.7	6.7	23.3
NPCC	13	7.7	38.5	7.7	7.7
SERC	28	35.7	42.9	7.1	42.9
SPP	25	36.0	52.0	20.0	52.0
WSCC	40	47.5	45.0	27.5	20.0

* Federal, State, and District systems

TABLE Q-20t:e-f

(20t:e-f) Is TRANSMISSION planning coordinated on a regular basis with:

		federal power authorities?		other?	
	COUNT	Yes	No	Yes	No
Generation:					
building	51	27.5%	60.8%	15.7%	41.2%
NOT building	135	26.7	53.3	16.3	35.6
Transmission:					
building	79	36.7	48.1	19.0	29.1
NOT building	107	19.6	60.7	14.0	43.0
Miles of transmission lines					
< 1000	103	21.4	57.3	12.6	37.9
> 1000	83	33.7	53.0	20.5	36.1
Reserve margin					
< 25%	67	34.3	47.8	16.4	32.8
> 25%	96	15.6	66.7	16.7	41.7
Member of a power pool?					
Yes	80	30.0	55.0	16.3	35.0
No	106	24.5	55.7	16.0	38.7

TABLE Q-21

(21) If your service area crosses state boundaries, does this have an effect on transmission planning?

	COUNT	Yes	No
ALL	83	53.0%	44.6%
IOUs	71	50.7	46.5
RECs	11	72.7	27.3
MUNIs	0	n/a	n/a
OTHER *	1	0.0	100.0
ECAR	16	0.0	100.0
ERCOT	0	n/a	n/a
MAAC	5	100.0	0.0
MAIN	5	0.0	100.0
MAPP	24	41.7	58.3
NPCC	6	100.0	0.0
SERC	2	100.0	0.0
SPP	14	85.7	14.3
WSCC	11	81.8	0.0

* Federal, State, and District systems

TABLE Q-21

(21) If your service area crosses state boundaries, does this have an effect on transmission planning?

	COUNT	Yes	No
Generation:			
building	28	42.9%	57.1%
NOT building	55	58.2	38.2
Transmission:			
building	60	48.3	48.3
NOT building	23	65.2	34.8
Miles of transmission lines			
< 1000	11	63.6	36.4
> 1000	72	51.4	45.8
Reserve margin			
< 25%	41	56.1	39.0
> 25%	41	51.2	48.8
Member of a power pool?			
Yes	63	57.1	42.9
No	20	40.0	50.0

TABLE Q-23:a

(23:a) Would you consider building a transmission line whose PRIMARY intention is:

	COUNT	(a) to provide INTER-state transmission service for others?			
		Yes	Possibly	Unlikely	No
ALL	186	8.1%	26.3%	25.8%	34.4%
IOUs	87	11.5	39.1	23.0	24.1
RECs	30	6.7	33.3	33.3	20.0
MUNIs	47	4.3	6.4	23.4	57.4
OTHER *	22	4.5	9.1	31.8	45.5
ECAR	23	0.0	26.1	21.7	43.5
ERCOT	8	0.0	12.5	12.5	62.5
MAAC	10	20.0	40.0	30.0	10.0
MAIN	9	0.0	33.3	55.6	11.1
MAPP	30	6.7	30.0	20.0	36.7
NPCC	13	23.1	15.4	23.1	38.5
SERC	28	3.6	46.4	32.1	10.7
SPP	25	8.0	28.0	20.0	44.0
WSCC	40	12.5	10.0	27.5	42.5

* Federal, State, and District systems

TABLE Q-23:a

(23:a) Would you consider building a transmission line whose PRIMARY intention is:

	COUNT	(a) to provide INTER-state transmission service for others?			
		Yes	Possibly	Unlikely	No
Generation:					
building	51	11.8%	41.2%	23.5%	21.6%
NOT building	135	6.7	20.7	26.7	39.3
Transmission:					
building	79	12.7	31.6	31.6	22.8
NOT building	107	4.7	22.4	21.5	43.0
Miles of transmission lines					
< 1000	103	7.8	12.6	23.3	48.5
> 1000	83	8.4	43.4	28.9	16.9
Reserve margin					
< 25%	67	11.9	31.3	22.4	29.9
> 25%	96	5.2	25.0	30.2	35.4
Member of a power pool?					
Yes	80	12.5	30.0	20.0	36.3
No	106	4.7	23.6	30.2	33.0

TABLE Q-23:b

(23:b) Would you consider building a transmission line whose PRIMARY intention is:

		(b) to provide INTRA-state transmission service for others?			
	COUNT	Yes	Possibly	Unlikely	No
ALL	186	12.4%	32.8%	21.5%	28.0%
IOUs	87	14.9	43.7	18.4	20.7
RECs	30	10.0	36.7	40.0	6.7
MUNIs	47	6.4	21.3	17.0	46.8
OTHER *	22	18.2	9.1	18.2	45.5
ECAR	23	0.0	30.4	39.1	21.7
ERCOT	8	12.5	50.0	0.0	25.0
MAAC	10	20.0	40.0	30.0	10.0
MAIN	9	11.1	33.3	44.4	11.1
MAPP	30	10.0	33.3	20.0	30.0
NPCC	13	23.1	23.1	7.7	46.2
SERC	28	7.1	57.1	17.9	10.7
SPP	25	12.0	32.0	16.0	40.0
WSCC	40	20.0	15.0	20.0	37.5

* Federal, State, and District systems

TABLE Q-23:b

(23:b) Would you consider building a transmission line whose PRIMARY intention is:

		(b) to provide INTRA-state transmission service for others?			
	COUNT	Yes	Possibly	Unlikely	No
Generation:					
building	51	15.7%	47.1%	17.6%	17.6%
NOT building	135	11.1	27.4	23.0	31.9
Transmission:					
building	79	19.0	39.2	20.3	20.3
NOT building	107	7.5	28.0	22.4	33.6
Miles of transmission lines					
< 1000	103	11.7	19.4	22.3	38.8
> 1000	83	13.3	49.4	20.5	14.5
Reserve margin					
< 25%	67	14.9	40.3	16.4	23.9
> 25%	96	9.4	31.3	27.1	28.1
Member of a power pool?					
Yes	80	13.8	36.3	17.5	31.3
No	106	11.3	30.2	24.5	25.5

TABLE Q-23:c

(23:c) Would you consider building a transmission line whose PRIMARY intention is:

	COUNT	(c) enhanced service area reliability?			
		Yes	Possibly	Unlikely	No
ALL	186	79.6%	16.1%	1.1%	0.5%
IOUs	87	82.8	14.9	0.0	0.0
RECs	30	76.7	16.7	3.3	0.0
MUNIs	47	83.0	10.6	2.1	2.1
OTHER *	22	63.6	31.8	0.0	0.0
ECAR	23	65.2	26.1	4.3	0.0
ERCOT	8	87.5	12.5	0.0	0.0
MAAC	10	100.0	0.0	0.0	0.0
MAIN	9	100.0	0.0	0.0	0.0
MAPP	30	76.7	16.7	3.3	0.0
NPCC	13	76.9	7.7	0.0	7.7
SERC	28	89.3	10.7	0.0	0.0
SPP	25	84.0	16.0	0.0	0.0
WSCC	40	70.0	25.0	0.0	0.0

* Federal, State, and District systems

TABLE Q-23:c

(23:c) Would you consider building a transmission line whose PRIMARY intention is:

	COUNT	(c) enhanced service area reliability?			
		Yes	Possibly	Unlikely	No
Generation:					
building	51	84.3%	13.7%	0.0%	0.0%
NOT building	135	77.8	17.0	1.5	0.7
Transmission:					
building	79	86.1	13.9	0.0	0.0
NOT building	107	74.8	17.8	1.9	0.9
Miles of transmission lines					
< 1000	103	76.7	16.5	1.9	1.0
> 1000	83	83.1	15.7	0.0	0.0
Reserve margin					
< 25%	67	83.6	14.9	0.0	0.0
> 25%	96	80.2	14.6	2.1	1.0
Member of a power pool?					
Yes	80	80.0	17.5	0.0	1.3
No	106	79.2	15.1	1.9	0.0

TABLE Q-23:d

(23:d) Would you consider building a transmission line whose PRIMARY intention is:

	COUNT	(d) to purchase power for your own use from other utilities?			
		Yes	Possibly	Unlikely	No
ALL	186	70.4%	21.0%	3.2%	3.2%
IOUs	87	75.9	23.0	0.0	0.0
RECs	30	70.0	26.7	0.0	0.0
MUNIs	47	61.7	17.0	8.5	10.6
OTHER *	22	68.2	13.6	9.1	4.5
ECAR	23	60.9	30.4	0.0	4.3
ERCOT	8	87.5	12.5	0.0	0.0
MAAC	10	80.0	20.0	0.0	0.0
MAIN	9	77.8	22.2	0.0	0.0
MAPP	30	60.0	26.7	6.7	3.3
NPCC	13	69.2	7.7	15.4	7.7
SERC	28	78.6	21.4	0.0	0.0
SPP	25	68.0	28.0	0.0	4.0
WSCC	40	72.5	12.5	5.0	5.0

* Federal, State, and District systems

TABLE Q-23:d

(23:d) Would you consider building a transmission line whose PRIMARY intention is:

	COUNT	(d) to purchase power for your own use from other utilities? Yes	Possibly	Unlikely	No
Generation:					
building	51	80.4%	13.7%	2.0%	2.0%
NOT building	135	66.7	23.7	3.7	3.7
Transmission:					
building	79	75.9	20.3	2.5	1.3
NOT building	107	66.4	21.5	3.7	4.7
Miles of transmission lines					
< 1000	103	65.0	20.4	5.8	5.8
> 1000	83	77.1	21.7	0.0	0.0
Reserve margin					
< 25%	67	79.1	19.4	0.0	1.5
> 25%	96	66.7	21.9	5.2	4.2
Member of a power pool?					
Yes	80	71.3	21.3	2.5	5.0
No	106	69.8	20.8	3.8	1.9

TABLE Q-23:e

(23:e) Would you consider building a transmission line whose PRIMARY intention is:

(e) increased opportunities to sell your existing generation to other utilities?

	COUNT	Yes	Possibly	Unlikely	No
ALL	186	37.1%	41.4%	10.2%	7.0%
IOUs	87	40.2	46.0	11.5	1.1
RECs	30	40.0	46.7	6.7	3.3
MUNIs	47	23.4	36.2	12.8	19.1
OTHER *	22	50.0	27.3	4.5	9.1
ECAR	23	26.1	60.9	4.3	4.3
ERCOT	8	87.5	0.0	12.5	0.0
MAAC	10	30.0	20.0	40.0	10.0
MAIN	9	55.6	33.3	11.1	0.0
MAPP	30	30.0	36.7	16.7	10.0
NPCC	13	38.5	23.1	15.4	23.1
SERC	28	25.0	50.0	10.7	7.1
SPP	25	36.0	60.0	0.0	4.0
WSCC	40	45.0	37.5	5.0	5.0

* Federal, State, and District systems

TABLE Q-23:e

(23:e) Would you consider building a transmission line whose PRIMARY intention is:

	COUNT	(e) increased opportunities to sell your existing generation to other utilities? Yes	Possibly	Unlikely	No
Generation:					
building	51	47.1%	45.1%	5.9%	0.0%
NOT building	135	33.3	40.0	11.9	9.6
Transmission:					
building	79	44.3	48.1	5.1	2.5
NOT building	107	31.8	36.4	14.0	10.3
Miles of transmission lines					
< 1000	103	33.0	36.9	10.7	12.6
> 1000	83	42.2	47.0	9.6	0.0
Reserve margin					
< 25%	67	41.8	41.8	14.9	1.5
> 25%	96	33.3	44.8	9.4	8.3
Member of a power pool?					
Yes	80	36.3	45.0	13.8	5.0
No	106	37.7	38.7	7.5	8.5

TABLE Q-23:f

(23:f) Would you consider building a transmission line whose PRIMARY intention is:

	COUNT	(f) to purchase power from one neighboring utility to sell to another?			
		Yes	Possibly	Unlikely	No
ALL	186	15.1%	35.5%	32.8%	12.4%
IOUs	87	18.4	44.8	28.7	5.7
RECs	30	13.3	30.0	50.0	3.3
MUNIs	47	10.6	27.7	25.5	29.8
OTHER *	22	13.6	22.7	40.9	13.6
ECAR	23	8.7	26.1	43.5	13.0
ERCOT	8	37.5	50.0	12.5	0.0
MAAC	10	10.0	40.0	40.0	10.0
MAIN	9	33.3	44.4	11.1	11.1
MAPP	30	10.0	30.0	40.0	13.3
NPCC	13	30.8	15.4	15.4	38.5
SERC	28	7.1	67.9	14.3	7.1
SPP	25	12.0	32.0	44.0	12.0
WSCC	40	17.5	25.0	40.0	10.0

* Federal, State, and District systems

TABLE Q-23:f

(23:f) Would you consider building a transmission line whose PRIMARY intention is:

(f) to purchase power from one neighboring utility to sell to another?

	COUNT	Yes	Possibly	Unlikely	No
Generation:					
building	51	19.6%	54.9%	13.7%	9.8%
NOT building	135	13.3	28.1	40.0	13.3
Transmission:					
building	79	19.0	48.1	27.8	5.1
NOT building	107	12.1	26.2	36.4	17.8
Miles of transmission lines					
< 1000	103	15.5	21.4	35.0	21.4
> 1000	83	14.5	53.0	30.1	1.2
Reserve margin					
< 25%	67	20.9	37.3	32.8	7.5
> 25%	96	11.5	36.5	34.4	13.5
Member of a power pool?					
Yes	80	16.3	37.5	36.3	10.0
No	106	14.2	34.0	30.2	14.2

TABLE Q-23:g

(23:g) Would you consider building a transmission line whose PRIMARY intention is:

(g) increased opportunities to sell power from your planned generating facilities to other utilities?

	COUNT	Yes	Possibly	Unlikely	No
ALL	186	29.0%	43.0%	14.0%	9.7%
IOUs	87	31.0	46.0	17.2	3.4
RECs	30	36.7	46.7	6.7	6.7
MUNIs	47	19.1	36.2	17.0	19.1
OTHER *	22	31.8	40.9	4.5	18.2
ECAR	23	21.7	52.2	4.3	13.0
ERCOT	8	50.0	37.5	12.5	0.0
MAAC	10	20.0	30.0	40.0	10.0
MAIN	9	44.4	44.4	11.1	0.0
MAPP	30	26.7	30.0	23.3	13.3
NPCC	13	30.8	30.8	7.7	30.8
SERC	28	17.9	53.6	14.3	7.1
SPP	25	28.0	52.0	16.0	4.0
WSCC	40	37.5	42.5	7.5	7.5

* Federal, State, and District systems

TABLE Q-23:g

(23:g) Would you consider building a transmission line whose PRIMARY intention is:

(g) increased opportunities to sell power from your planned generating facilities to other utilities?

	COUNT	Yes	Possibly	Unlikely	No
Generation:					
building	51	33.3%	52.9%	7.8%	3.9%
NOT building	135	27.4	39.3	16.3	11.9
Transmission:					
building	79	36.7	50.6	7.6	5.1
NOT building	107	23.4	37.4	18.7	13.1
Miles of transmission lines					
< 1000	103	25.2	36.9	16.5	15.5
> 1000	83	33.7	50.6	10.8	2.4
Reserve margin					
< 25%	67	35.8	44.8	13.4	6.0
> 25%	96	25.0	43.8	16.7	9.4
Member of a power pool?					
Yes	80	30.0	43.8	17.5	8.8
No	106	28.3	42.5	11.3	10.4

STATE REGULATION OF TRANSMISSION LINE PLANNING AND SITING

Questions 11, 12, 14, 17, and 24 asked for information on utility perceptions of state regulation of transmission line planning and siting. The utility responses for each question are summarized in the correspondingly numbered Tables below.

QUESTION 11.

Question 11 asked whether preparation of a forecast of demand, supply or transmission is required by law or rule. For all utility types, reliability regions and subsets, a demand forecast is somewhat more often required than is a supply forecast; and a transmission forecast is noticeably less often required than are demand and supply forecasts. IOU and REC respondents answered "yes" noticeably more often then did MUNI and Other respondents.

When the various subsets are examined, the most noticeable difference is that respondents with more than 1000 miles of transmission lines answered "yes" more often than any other subset.

QUESTION 12.

Question 12 asked how frequently the forecasts of demand (question 12d), supply (question 12s), and transmission (question 12t) are prepared. In general demand forecasts are prepared more frequently than supply forecasts, which in turn are prepared more frequently than transmission forecasts. For all three forecasts, a higher percentage of IOU respondents prepares the forecast annually than for the remaining three utility types. This difference is most noticeable for transmission forecasts which 80% of IOU respondents prepare annually compared with 35% of the remaining respondents.

For respondents who are building generation 98% forecast demand annually and 91% forecast supply annually.

QUESTION 14.

Question 14 asked whether demand, supply, and transmission forecasts are subject to state regulatory review. Demand and supply forecasts are subject to state regulatory review for approximately 60% of the IOU respondents, but for only 25% of the remainder. Transmission forecasts are in general less frequently subject to state regulatory review. Approximately 40% of IOU respondents answered "yes" for transmission forecasts, while only 15% of the remainder responded "yes".

For each reliability region and for all subsets, transmission forecasts are less often subject to state regulatory review than are demand and supply forecasts.

QUESTION 17.

Question 17 asked whether the state in which transmission facilities existed or were planned has a process to regulate siting. 74% of all respondents answered "yes". Of the respondents who answered "no", three-quarters are in the ECAR, SERC, and SPP regions.

QUESTION 24.

Question 24 asked whether there are circumstances in which a certificate could be obtained for a transmission line which serves the national interest, but does not substantially serve ratepayers. Many respondents did not answer this question "yes" or "no", but responded: "unknown", "no experience", "federal agency would build such a line", "ask the regulators", etc. Over all, approximately one-half answered "no", one-quarter answered "yes" and one-quarter did not answer. Thus, of those who did answer, approximately two-thirds responded "no".

For all utility types more respondents answered "no" than answered "yes". Federal, state, and district systems had the lowest "no" response rate. For reliability regions, respondents in NPCC and WSCC answered "yes" more often than "no". For the analyzed subsets, there are no noticeable differences; approximately two-thirds of those who responded said "no".

TABLE Q-11

(11) Are you required by law or rule to prepare the forecast of:

	COUNT	DEMAND?		SUPPLY?		TRANSMISSION?	
		Yes	No	Yes	No	Yes	No
ALL	235	65.5%	33.6%	61.3%	37.4%	45.5%	50.6%
IOUs	130	71.5	26.9	70.0	28.5	53.8	43.8
RECs	36	77.8	22.2	72.2	27.8	63.9	36.1
MUNIs	47	53.2	46.8	40.4	57.4	19.1	68.1
OTHER *	22	36.4	63.6	36.4	63.6	22.7	77.3
ECAR	35	51.4	45.7	51.4	45.7	40.0	54.3
ERCOT	8	75.0	25.0	75.0	25.0	25.0	62.5
MAAC	10	90.0	10.0	90.0	10.0	70.0	30.0
MAIN	11	81.8	18.2	72.7	27.3	36.4	63.6
MAPP	44	70.5	29.5	68.2	31.8	61.4	38.6
NPCC	17	58.8	41.2	52.9	47.1	35.3	52.9
SERC	29	65.5	31.0	55.2	37.9	34.5	58.6
SPP	34	67.6	32.4	64.7	35.3	47.1	50.0
WSCC	47	61.7	38.3	55.3	44.7	44.7	53.2

* Federal, State, and District systems

TABLE Q-11

(11) Are you required by law or rule to prepare the forecast of:

		DEMAND?		SUPPLY?		TRANSMISSION?	
	COUNT	Yes	No	Yes	No	Yes	No
Generation:							
building	67	70.1%	29.9%	65.7%	34.3%	53.7%	46.3%
NOT building	168	63.7	35.1	59.5	38.7	42.3	52.4
Transmission:							
building	117	68.4	31.6	65.8	34.2	53.8	45.3
NOT building	118	62.7	35.6	56.8	40.7	37.3	55.9
Miles of transmission lines							
< 1000	108	54.6	44.4	49.1	49.1	28.7	63.9
> 1000	127	74.8	24.4	71.7	27.6	59.8	39.4
Reserve margin							
< 25%	92	68.5	30.4	65.2	33.7	50.0	47.8
> 25%	120	68.3	30.8	62.5	35.8	45.8	48.3
Member of a power pool?							
Yes	119	72.3	26.9	69.7	29.4	54.6	42.9
No	116	58.6	40.5	52.6	45.7	36.2	58.6

TABLE Q-12d

(12d) How frequently is the forecast of DEMAND prepared?

	COUNT	annually	every 2 to 5 years	when a rate case is filed	with a request for certification	other (**)
ALL	235	86.8%	9.8%	0.0%	0.9%	0.9%
IOUs	130	93.8	3.8	0.0	0.8	1.5
RECs	36	77.8	16.7	0.0	2.8	0.0
MUNIs	47	80.9	12.8	0.0	0.0	0.0
OTHER *	22	72.7	27.3	0.0	0.0	0.0
ECAR	35	94.3	2.9	0.0	0.0	0.0
ERCOT	8	100.0	0.0	0.0	0.0	0.0
MAAC	10	100.0	0.0	0.0	0.0	0.0
MAIN	11	63.6	18.2	0.0	9.1	9.1
MAPP	44	81.8	11.4	0.0	0.0	2.3
NPCC	17	88.2	5.9	0.0	0.0	0.0
SERC	29	86.2	10.3	0.0	3.4	0.0
SPP	34	91.2	8.8	0.0	0.0	0.0
WSCC	47	83.0	17.0	0.0	0.0	0.0

* Federal, State, and District systems

** "every 6 to 12 months"

TABLE Q-12d

(12d) How frequently is the forecast of DEMAND prepared?

	COUNT	annually	every 2 to 5 years	when a rate case is filed	with a request for certification	other (*)
Generation:						
building	67	98.5%	1.5%	0.0%	0.0%	0.0%
NOT building	168	82.1	13.1	0.0	1.2	1.2
Transmission:						
building	117	89.7	8.5	0.0	0.0	0.9
NOT building	118	83.9	11.0	0.0	1.7	0.8
Miles of transmission lines						
< 1000	108	78.7	15.7	0.0	0.9	0.9
> 1000	127	93.7	4.7	0.0	0.8	0.8
Reserve margin						
< 25%	92	89.1	8.7	0.0	0.0	1.1
> 25%	120	89.2	6.7	0.0	1.7	0.8
Member of a power pool?						
Yes	119	90.8	6.7	0.0	0.8	0.8
No	116	82.8	12.9	0.0	0.9	0.9

* "every 6 to 12 months"

TABLE Q-12s

(12s) How frequently is the forecast of SUPPLY prepared?

	COUNT	annually	every 2 to 5 years	when a rate case is filed	with a request for certification	other (**)
ALL	235	71.5%	19.6%	0.9%	0.9%	3.0%
IOUs	130	82.3	13.8	0.8	0.8	2.3
RECs	36	50.0	44.4	0.0	2.8	0.0
MUNIs	47	61.7	12.8	0.0	0.0	6.4
OTHER *	22	63.6	27.3	4.5	0.0	4.5
ECAR	35	85.7	11.4	0.0	0.0	0.0
ERCOT	8	100.0	0.0	0.0	0.0	0.0
MAAC	10	80.0	10.0	0.0	0.0	10.0
MAIN	11	27.3	63.6	0.0	9.1	0.0
MAPP	44	68.2	20.5	0.0	0.0	2.3
NPCC	17	82.4	0.0	5.9	0.0	0.0
SERC	29	69.0	13.8	0.0	3.4	6.9
SPP	34	64.7	29.4	0.0	0.0	2.9
WSCC	47	70.2	23.4	2.1	0.0	4.3

* Federal, State, and District systems

** "as needed"

TABLE Q-12s

(12s) How frequently is the forecast of SUPPLY prepared?

	COUNT	annually	every 2 to 5 years	when a rate case is filed	with a request for certification	other (*)
Generation:						
building	67	91.0%	7.5%	0.0%	0.0%	1.5%
NOT building	168	63.7	24.4	1.2	1.2	3.6
Transmission:						
building	117	75.2	19.7	1.7	0.0	1.7
NOT building	118	67.8	19.5	0.0	1.7	4.2
Miles of transmission lines						
< 1000	108	63.0	19.4	1.9	0.9	5.6
> 1000	127	78.7	19.7	0.0	0.8	0.8
Reserve margin						
< 25%	92	81.5	13.0	1.1	0.0	3.3
> 25%	120	67.5	21.7	0.0	1.7	2.5
Member of a power pool?						
Yes	119	80.7	14.3	0.8	0.8	1.7
No	116	62.1	25.0	0.9	0.9	4.3

* "as needed"

TABLE Q-12t

(12t) How frequently is the forecast of TRANSMISSION prepared?

	COUNT	annually	every 2 to 5 years	when a rate case is filed	with a request for certification	other (**)
ALL	235	60.9%	19.6%	0.0%	0.9%	6.0%
IOUs	130	80.8	8.5	0.0	0.0	6.9
RECs	36	44.4	41.7	0.0	0.0	0.0
MUNIs	47	27.7	31.9	0.0	4.3	2.1
OTHER *	22	40.9	22.7	0.0	0.0	18.2
ECAR	35	65.7	17.1	0.0	0.0	2.9
ERCOT	8	75.0	0.0	0.0	0.0	0.0
MAAC	10	80.0	10.0	0.0	0.0	10.0
MAIN	11	18.2	54.5	0.0	0.0	18.2
MAPP	44	59.1	25.0	0.0	2.3	2.3
NPCC	17	76.5	0.0	0.0	0.0	0.0
SERC	29	55.2	27.6	0.0	3.4	0.0
SPP	34	67.6	14.7	0.0	0.0	11.8
WSCC	47	55.3	19.1	0.0	0.0	10.6

* Federal, State, and District systems

** "as needed", "as required"

TABLE Q-12t

(12t) How frequently is the forecast of TRANSMISSION prepared?

	COUNT	annually	every 2 to 5 years	when a rate case is filed	with a request for certification	other (*)
Generation:						
building	67	83.6%	9.0%	0.0%	0.0%	3.0%
NOT building	168	51.8	23.8	0.0	1.2	7.1
Transmission:						
building	117	68.4	19.7	0.0	0.9	6.0
NOT building	118	53.4	19.5	0.0	0.8	5.9
Miles of transmission lines						
< 1000	108	44.4	23.1	0.0	1.9	5.6
> 1000	127	74.8	16.5	0.0	0.0	6.3
Reserve margin						
< 25%	92	70.7	19.6	0.0	1.1	3.3
> 25%	120	57.5	19.2	0.0	0.8	7.5
Member of a power pool?						
Yes	119	73.1	10.9	0.0	0.8	7.6
No	116	48.3	28.4	0.0	0.9	4.3

* "as needed", "as required"

TABLE Q-14

(14) Are these forecasts subject to state regulatory review?

		Demand Forecast		Supply Forecast		Transmission Forecast	
	COUNT	Yes	No	Yes	No	Yes	No
ALL	235	44.3%	53.6%	44.7%	51.9%	30.6%	62.1%
IOUs	130	59.2	38.5	61.5	35.4	43.1	52.3
RECs	36	30.6	69.4	36.1	63.9	27.8	66.7
MUNIs	47	29.8	68.1	21.3	72.3	10.6	76.6
OTHER *	22	9.1	86.4	9.1	86.4	4.5	81.8
ECAR	35	40.0	57.1	40.0	57.1	34.3	62.9
ERCOT	8	50.0	50.0	50.0	50.0	12.5	87.5
MAAC	10	70.0	30.0	70.0	30.0	60.0	40.0
MAIN	11	54.5	45.5	45.5	45.5	27.3	63.6
MAPP	44	50.0	47.7	50.0	47.7	36.4	54.5
NPCC	17	52.9	41.2	52.9	35.3	35.3	35.3
SERC	29	51.7	44.8	48.3	44.8	34.5	62.1
SPP	34	20.6	79.4	29.4	70.6	8.8	91.2
WSCC	47	42.6	55.3	42.6	55.3	31.9	57.4

* Federal, State, and District systems

TABLE Q-14

(14) Are these forecasts subject to state regulatory review?

	COUNT	Demand Forecast		Supply Forecast		Transmission Forecast	
		Yes	No	Yes	No	Yes	No
Generation:							
building	67	53.7%	44.8%	50.7%	46.3%	38.8%	58.2%
NOT building	168	40.5	57.1	42.3	54.2	27.4	63.7
Transmission:							
building	117	46.2	53.0	49.6	48.7	38.5	57.3
NOT building	118	42.4	54.2	39.8	55.1	22.9	66.9
Miles of transmission lines							
< 1000	108	32.4	65.7	31.5	64.8	16.7	71.3
> 1000	127	54.3	43.3	55.9	40.9	42.5	54.3
Reserve margin							
< 25%	92	51.1	47.8	53.3	45.7	39.1	58.7
> 25%	120	45.8	51.7	45.0	50.0	29.2	60.8
Member of a power pool?							
Yes	119	53.8	43.7	56.3	41.2	39.5	53.8
No	116	34.5	63.8	32.8	62.9	21.6	70.7

TABLE Q-17

(17) Does the state in which you have, or plan to have, transmission facilities have a process to regulate the siting of transmission facilities?

	COUNT	Yes	No
ALL	235	74.0%	21.3%
IOUs	130	83.8	15.4
RECs	36	69.4	27.8
MUNIs	47	55.3	34.0
OTHER *	22	63.6	18.2
ECAR	35	62.9	31.4
ERCOT	8	100.0	0.0
MAAC	10	90.0	10.0
MAIN	11	81.8	9.1
MAPP	44	90.9	2.3
NPCC	17	94.1	0.0
SERC	29	55.2	41.4
SPP	34	58.8	41.2
WSCC	47	72.3	21.3

* Federal, State, and District systems

TABLE Q-17

(17) Does the state in which you have, or plan to have, transmission facilities have a process to regulate the siting of transmission facilities?

	COUNT	Yes	No
Generation:			
building	67	80.6%	19.4%
NOT building	168	71.4	22.0
Transmission:			
building	117	76.9	22.2
NOT building	118	71.2	20.3
Miles of transmission lines			
< 1000	108	65.7	24.1
> 1000	127	81.1	18.9
Reserve margin			
< 25%	92	78.3	18.5
> 25%	120	74.2	21.7
Member of a power pool?			
Yes	119	88.2	10.9
No	116	59.5	31.9

TABLE Q-24

(24) Within the regulatory framework you currently face, are there circumstances in which you could obtain a cerificate for a transmission line crossing your service area which serves the national interest, but does not substantially serve your ratepayers?

	COUNT	Yes	No
ALL	235	26.0%	47.7%
IOUs	130	26.9	54.6
RECs	36	30.6	38.9
MUNIs	47	21.3	42.6
OTHER *	22	22.7	31.8
ECAR	35	11.4	62.9
ERCOT	8	25.0	37.5
MAAC	10	0.0	70.0
MAIN	11	45.5	45.5
MAPP	44	22.7	50.0
NPCC	17	47.1	29.4
SERC	29	17.2	51.7
SPP	34	23.5	50.0
WSCC	47	40.4	34.0

* Federal, State, and District systems

TABLE Q-24

(24) Within the regulatory framework you currently face, are there circumstances in which you could obtain a cerificate for a transmission line crossing your service area which serves the national interest, but does not substantially serve your ratepayers?

	COUNT	Yes	No
Generation:			
building	67	22.4%	53.7%
NOT building	168	27.4	45.2
Transmission:			
building	117	28.2	52.1
NOT building	118	23.7	43.2
Miles of transmission lines			
< 1000	108	23.1	41.7
> 1000	127	28.3	52.8
Reserve margin			
< 25%	92	30.4	53.3
> 25%	120	22.5	45.8
Member of a power pool?			
Yes	119	27.7	52.9
No	116	24.1	42.2

APPENDIX Q-1

Allegheny Power System (holding company)

American Electric Power System (holding company)

California Power Pool

Illinois-Missouri Pool

Mid-Continent Area Power Pool

Middle South Utilities (holding company)

Missouri-Kansas Pool

New England Power Pool

New York Power Pool

Pacific Northwest Coordination Agreement

Pennsylvania-New Jersy-Maryland Interconnection

Southern Company System (holding company)

Texas Municipal Power Pool

Texas Utilities Company (holding company)

Wisconsin Power Pool

APPENDIX Q-2

Listing of Respondents by Type

Investor-Owned

ALABAMA POWER COMPANY
ALLEGHENY POWER SYSTEM
AMERICAN ELECTRIC POWER
ARIZONA PUBLIC SERVICE CO.
ARKANSAS POWER & LIGHT COMPANY
ATLANTIC CITY ELECTRIC
BALTIMORE GAS & ELECTRIC CO.
BANGOR HYDRO-ELECTRIC CO.
CAROLINA POWER & LIGHT COMPANY
CENTEL ELECTRIC - WESTRN POWER
CENTERIOR ENERGY
CENTRAL ILLINOIS LIGHT COMPANY
CENTRAL ILLINOIS PUBLIC SER CO
CENTRAL LOUISIANA ELECTRIC
CENTRL HUDSON GAS & ELECTRIC
CINCINNATI GAS & ELECTRIC CO.
COMMONWEALTH EDISON COMPANY
CONSOLIDATED EDISON CO OF NY
DUKE POWER COMPANY
DUQUESNE LIGHT COMPANY
EASTERN UTILITIES ASSOC.
FLORIDA POWER CORPORATION
FLORIDA POWER & LIGHT COMPANY
GEORGIA POWER COMPANY
GULF POWER COMPANY
HAWAIIAN ELECTRIC CO
ILLINOIS POWER COMPANY
INDIANAPOLIS POWER & LIGHT CO.
IOWA POWER AND LIGHT COMPANY
IOWA PUBLIC SERVICE COMPANY
MISSOURI PUBLIC SERVICE
MONTANA POWER COMPANY
MONTANA-DAKOTA UTILITIES CO.
NEVADA POWER COMPANY
NEW ENGLAND ELECTRIC SYSTEM
NEW ORLEANS PUBLIC SERVICE INC
NEW YORK STATE ELEC & GAS CORP
NORTHERN INDIANA PUB. SERV. CO
NORTHERN STATES POWER-MINN CO
NORTHERN STATES POWER-WISC CO
NORTHWESTERN PUBLIC SERVICE CO
OHIO EDISON SYSTEM
OTTER TAIL POWER COMPANY
PACIFIC GAS & ELECTRIC COMPANY
PACIFIC POWER & LIGHT CO.
PENNSYLVANIA ELECTRIC CO.
PHILADELPHIA ELECTRIC COMPANY
PORTLAND GENERAL ELECTRIC
POTOMAC ELECTRIC POWER COMPANY
PUB SERV. CO. OF NEW HAMPSHIRE
PUBLIC SERVICE CO. OF OKLAHOMA
PUBLIC SERVICE ELEC & GAS
PUBLIC SERVICE OF COLORADO
PUBLIC SERVICE OF NEW MEXICO
PUBLIC SERV. CO OF INDIANA INC
ROCHESTER GAS & ELECTRIC CORP.
SAN DIEGO GAS & ELECTRIC CO.
SAVANNAH ELECTRIC & POWER CO.
SIERRA PACIFIC POWER COMPANY
SOUTH CAROLINA ELEC. & GAS CO.

Appendix 2 (cont.)

Investor-Owned (Cont.)

IOWA SOUTHERN UTILITIES CO.
IOWA-ILLINOIS GAS & ELEC. CO.
JERSEY CENTRAL POWER & LIGHT
KANSAS CITY POWER & LIGHT CO.
KANSAS GAS & ELECTRIC COMPANY
KANSAS POWER AND LIGHT CO.
KENTUCKY UTILITIES COMPANY
LOUISIANA POWER & LIGHT CO.
LOUISVILLE GAS & ELECTRIC CO.
MADISON GAS & ELECTRIC CO.
METROPOLITAN EDISON COMPANY
MINNESOTA POWER AND LIGHT
MISSISSIPPI POWER CO.
MISSISSIPPI POWER & LIGHT CO.
SOUTHERN CALIFORNIA EDISON CO.
SOUTHERN INDIANA GAS & ELEC CO
SOUTHWESTERN ELECTRIC POWER CO
ST. JOSEPH LIGHT & POWER CO.
TEXAS UTILITIES ELECTRIC CO.
THE EMPIRE DISTRICT ELECT. CO.
UGI CORP., LUZERNE ELEC. DIV.
UNITED ILLUMINATING COMPANY
VIRGINIA POWER
WASHINGTON WATER POWER CO.
WEST TEXAS UTILITIES COMPANY
WISCONSIN ELECTRIC POWER CO.
WISCONSIN PUBLIC SERVICE CORP.

Municipals

ANCHORAGE MUNI LIGHT & POWER
BRAINTREE ELECTRIC LIGHT DEPT.
CEDAR FALLS UTILITIES
CITY OF AUSTIN ELEC. UTL. DEPT
CITY OF BROOKINGS ELEC DEPT.
CITY OF CLEWISTON
CITY OF COLORADO SPRINGS
CITY OF COLUMBUS
CITY OF FARMINGTON
CITY OF HOLLAND
CITY OF HOLYOKE
CITY OF HOMESTEAD
CITY OF LAFAYETTE
CITY OF ORRVILLE, DPU
CITY OF TACOMA
CITY UTIL. OF SPRINGFIELD, MO.
DANVILLE WATER, GAS & ELEC.
GAINESVILLE REGIONAL UTILITIES
GARLAND POWE SYSTEM
GLENDALE PUBLIC SERVICE DEPT.
JACKSONVILLE ELECTRIC AUTH.
LOS ANGELES DEP OF WTR & PWR
LUBBOCK POWER AND LIGHT
MANITOWOC PUBLIC UTILITIES
MARSHFIELD ELECTRIC & WATER
MCPHERSON BOARD OF UTILITIES
MEMPHIS LIGHT, GAS & WATER DIV
MENASHA ELECTRIC & WATER
MOORHEAD PUBLIC SERV. DEPT.
MUSCATINE POWER & LIGHT
NASHVILLE ELECTRIC SERVICE
ORLANDO UTILITIES COMMISSION
OWENSBORO MUNICIPAL UTILITY
PADUCAH POWER SYSTEM
PIERRE MUNICIPAL UTILITIES
RIVIERA UTILITIES
ROCHESTER PUBLIC UTILITIES
SALUDA RIVER ELEC. COOP., INC.
SAN ANTONIO CITY PUBLIC SERV.
SANTA CLARA ELECTRIC DEPT.
SPENCER MUNICIPAL UTILITIES
THE CITY OF GROTON

Municipal (Cont.)

KANSAS CITY BOARD OF UTILITIES
KISSIMMEE UTILITY AUTHORITY
LANSING BOARD OF WATER & LIGHT
VILLAGE OF ARCADE
WATERTOWN MUNICIPAL UTIL.

Rural Electric Cooperatives

ALLEGHENY ELECTRIC COOP., INC.
ARIZONA ELECTRIC POWER COOP.
ASSOCIATED ELECTRIC COOP., INC
BASIN ELECTRIC POWER COOP
BIG RIVERS ELECTRIC CORP.
BRAZOS ELECTRIC POWER COOP INC
BUCKEYE POWER, INC.
CAJUN ELECTRIC POWER COOP
CHUGACH ELECTRIC ASSOC.
COOPERATIVE POWER ASSOC.
CORN BELT POWER COOPERATIVE
DAIRYLAND POWER COOPERATIVE
DESERET GENERATION & TRAN COOP
EAST KENTUCKY POWER COOP. INC.
HOOSIER ENERGY RURAL ELEC COOP
KAMO ELECTRIC COOPERATIVE, INC
L AND O POWER COOPERATIVE
MINNKOTA POWER COOP., INC.
NO CAROLINA ELEC MEMBERSHIP
NORTHWEST IOWA POWER COOP.
OGLETHORPE POWER CORPORATION
PACIFIC NW GENERATING CO.
PLAINS ELEC GEN & TRANS COOP.
SEMINOLE ELECTRIC COOP. INC.
SOUTH TEXAS ELECTRIC COOP. INC
SOUTHERN ILLINOIS POWER COOP.
SO. MISSISSIPPI ELEC PWR ASSOC
SUNFLOWER ELECTRIC COOPERATIVE
UNITED POWER ASSOCIATION
WESTERN FARMERS ELECTRIC COOP

Other Ownership Types

ALABAMA MUNICIPAL ELEC. AUTH.
BENTON COUNTY P.U.D.
CHELAN COUNTY P.U.D.
CLARK COUNTY P.U.D.
COWLITZ COUNTY P.U.D.
DOUGLAS COUNTY P.U.D.
GRANT COUNTY P.U.D.
GRAYS HARBOR COUNTY P.U.D.
IMPERIAL IRRIGATION DISTRICT
INDIANA MUNI. POWER AUTHORITY
LEWIS COUNTY P.U.D.
MISSOURI JOINT MUNI ELEC UTIL
MUNI ENERGY AGENCY OF MISS.
MUNICIPAL ELEC AUTH OF GEORGIA
OMAHA PUBLIC POWER DISTRICT
SACRAMENTO DEPT WATER RESOURCE
SALT RIVER PROJECT
TEXAS MUNICIPAL POWER AGENCY
TILLAMOOK PEOPLE'S UTIL. DIST.
TURLOCK IRRIGATION DISTRICT
UTAH ASSOC MUNI POWER SYSTEMS
WYOMING MUNICIPAL POWER AGENCY

OTA DRAFT WORKING PAPER

SUMMARY OF RESPONSES OF THE REGIONAL RELIABILITY COUNCILS TO THE NATIONAL GOVERNORS' ASSOCIATION SURVEY ON ELECTRIC TRANSMISSION COORDINATION AND PLANNING

JULY 1988

Note: This document was prepared by staff members of the Public Utilities Commission of the State of Ohio under Contract with the U.S. Congress, Office of Technology Assessment, Washington, D.C. This document was prepared for reference purposes and is being distributed for review and comment only and should not otherwise be reproduced, referenced, or quoted. The conclusions expressed in this paper are those of the authors and do not necessarily reflect the views of the Office of Technology Assessment, the Public Utilities Commission of Ohio or the National Governors' Association Task Force on Electricity Transmission. This document has not been reviewed or approved by the Technology Assessment Board.

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THE REGIONAL RELIABILITY COUNCILS
TO
THE NATIONAL GOVERNORS' ASSOCIATION SURVEY
ON ELECTRIC TRANSMISSION COORDINATION AND PLANNING

Draft for
The Office of Technology Assessment
March 28, 1988

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INTRODUCTION

This report summarizes the responses of the Regional Reliability Councils to a survey administered by the National Governors' Association in late 1986 and early 1987 concerning electric transmission coordination and planning. It is intended that the narrative which follows will be integrated into the final report to OTA, which will incorporate an analysis of all survey and interview responses gathered in the National Governors' Association's effort to collect information from the electric utility industry and its regulators regarding electric transmission system planning and coordination.

Throughout the text, references to Appendix R-1 are evident. Appendix R-1 is a compilation of the materials submitted in response to the Regional Reliability Council survey which were deemed relevant to OTA's assessment of the potential for increased competition in the electric utility industry. Materials referred to in Appendix R-1 but not included were (in almost every instance) submitted in Regional Reliability Council responses, and are available upon request from the Public Utilities Commission of Ohio.

Although NERC's "1987 Reliability Assessment" was not submitted in response to the survey (the "1986 Reliability Assessment" was submitted by NERC), it is referenced in several instances in the interest of providing more timely and relevant responses.

RELIABILITY COUNCIL GOALS AND OBJECTIVES

NERC

The North American Electric Reliability Council (NERC) is an international electric utility organization whose mission is to actively promote the reliability of the bulk power systems in North America. The purposes for its formation are stated in its "Certificate of Incorporation", revised in 1982 (Appendix R-1, p. 25). These purposes are:

1) to promote bulk power supply reliability and adequacy;
2) to conduct interregional studies concerning reliability and adequacy and to disseminate such information;
3) to encourage and assist the development of interregional reliability arrangements;
4) to exchange information with respect to planning and operating matters relating to reliability and adequacy;
5) to review regional and interregional activities on reliability and adequacy; and
6) to provide independent reviews of interregional matters referred to it by the Regional Councils.

NERC's functions and activities are more fully described in "Objectives of NERC, Adopted by Board of Trustees, July 7, 1978" (Appendix R-1, p. 26). Among the objectives enumerated therein is to "avoid encrouachment by the government into the utility industry". NERC has established certain Policies, Criteria and Guides to structure planning, engineering and operation so as to achieve its reliability objectives. These are described on pages 182-183 of Appendix R-1.

While the nine Regional Councils have defined their own goals and objectives, each Council's goals and objectives share NERC's predominant emphasis on the promotion of reliability of bulk electric supply systems.

ECAR

The goal of ECAR is "..further to augment reliability of the parties' bulk power supply through coordination of the parties' planning and operation of their generation and transmission facilities" ("ECAR Coordination Agreement, August 1, 1967", Appendix R-1. p. 27). Article 2 of the Agreement articulates specific principles and procedures to be periodically reviewed by the Executive Board, including the evaluation and simulated testing of systems' performance.

ERCOT

ERCOT's purpose is set forth in Article 1 of the "ERCOT Agreement, September 27, 1985" (Appendix R-1, p. 28). The purpose is to promote the reliable operation of power systems by various means including exchanging information, maintaining communication channels, providing a means for making regional studies designed to increase system reliability, and maintaining reliability through coordination of members' planning and operation.

MAAC

The "Mid-Atlantic Area Coordination Agreement Amendment, April 23, 1971" states that the Council's purpose is "to augment further the reliability of the bulk electric supply systems of the signatories through a higher degree of coordinated planning of their generation and transmission facilities" (Appendix R-1, p. 30).

MAIN

Section 1.1 of the MAIN Agreement states that the Council's purpose is "to promote maximum coordination of planning, construction, and utilization of generation and transmission facilities on a regional basis by MAIN members individually and as members of the pools to which they belong in order to improve the reliability and adequacy of bulk power supply in the area served by such members and pools." Section 1.3 of the Agreement, "Planning and Operating for Economy", states that "nothing herein restricts groups of MAIN members from developing, planning and operating arrangements to achieve increased economies in bulk power supply..." (Appendix R-1, p. 30).

Additional administrative purposes of MAIN are set forth in Section 1.2 of the Agreement (Appendix R-1, p. 31).

MAPP

The "MAPP Power Pool Agreement of March 31, 1972, Amended May 1, 1985", states in Article 1.01 that the Council's objective is "to provide reliable and economical electric service to the customers of each of the Parties consistent with reasonable utilization of natural resources and effect on the environment. In order to accomplish such purposes, the Parties shall endeavor to coordinate the installation and operation of generation and transmission facilities..." (Appendix R-1, pp. 32-33).

NPCC

NPCC's "Memorandum of Agreement, January 1966, Amended October 6, 1977" states the purpose of the Council. However, only pages 2 and 4 of the Memorandum of Agreement were sent in response to the survey, and these pages did not state the purpose of the Council. The 1986 Annual Report of NERC states, however, that "it is the intent of NPCC and its systems to continue to conduct appropriate interregional and intraregional reliability studies and for the systems to schedule electricity transfers so as to maintain a reliable and secure operating system (p. 46).

SERC

Article 2 of the "SERC Agreement, Amended April 10, 1985" states that "the purpose of this agreement is to augment further the reliability and adequacy of bulk power supply in the areas served by the Member Systems" (Appendix R-1, p. 33). To this end, the Council encourages the development of reliability and adequacy arrangements, exchanges information with respect to planning and operating, periodically reviews activities in the region on reliability and adequacy, and provides relevant information where appropriate to agencies of government.

SPP

SPP's "Second Coordination Agreement, Amended January 1, 1980" states the Council's general purposes in Article II (Appendix R-1, p. 36). These include:

1) encouraging greater joint planning and coordination of the generation and transmission systems of the parties and participating in interregional studies so as to provide for increased operating efficiency, adequate bulk power supply systems, and better service reliability, in the SPP and contiguous regions;
2) providing for the exchange of pertinent information;
3) disseminating information;
4) recommending minimum standards for interconnected operation; and
5) encouraging such transmission line interconnections and interconnection contracts among SPP and neighboring system members as may be necessary or desirable for promoting coordinated operation, increasing operating efficiency and providing better service reliability.

WSCC

Article 1 of the "WSCC Agreement, January 1, 1982" states that the "purpose of the Western Systems Coordinating Council is to promote the reliable operation of the interconnected bulk power systems by the coordination of planning and operation of generating and interconnected transmission facilities. The Council will provide formal means of exchanging information and system data and for making necessary regional studies and recommendations designed to increase the reliability of the interconnected bulk power systems" (Appendix R-1, p. 37).

INTERREGIONAL AGREEMENTS

Several formal reliability agreements bridge the boundaries of the Regional Councils. These are listed on page 64 of Appendix R-1. The final draft of "Overview of Planning Reliability Criteria among the Regional Reliability Councils of NERC, December 1987" notes that the statements of purpose in such agreements are "based on the recognition of the need to consider interregional as well as intraregional effects, and that examining the interfaces between areas must be a factor in overall bulk power system reliability. Thus, the agreements stress the free interregional exchange of information on demands, generation, and system plans. Most also include statements stressing coordination of planning. Some call for coordination of planning and operation, or even of planning, construction, operation and system protection. The differences in wording does not appear to be symptomatic of any differences in the desire to achieve reliability" (Appendix R-1, pp. 86-87).

Appendix R-1, Exhibits 20, 36, 37, and 38 (pp. 69a, 91a-91c) provide summary information on interregional agreements between and among the Regional Councils.

RELIABILITY COUNCIL ORGANIZATION

NERC

NERC is a "federation" of the nine Regional Reliability Councils whose utility members account for virtually all electric supply in North America. Regional Councils outside the contiguous United States, whose systems are not interconnected with systems which are members of the nine Regional Councils, may become non-voting "affiliates" of NERC, subject to a vote of NERC's Board of Trustees. There is currently one Affiliate represented.

The Board of Trustees directs NERC's overall activities. It is comprised of twenty-five utility executives, including two from each Regional Council. The Board elects other representatives as needed to assure at least one representative from a Canadian utility and at least two representatives from each utility ownership segment: federal, investor-owned, rural electric cooperative, and state/municipal systems. A quorum is constituted by a majority of those entitled to be present. The Board meets at least annually. The Board's Executive Committee is composed of the Chair, Past Chair, President, Secretary-Treasurer, and one member selected by the Board of Trustees.

The technical activities of the Council are carried out by its Engineering and Operating Committees and their many subgroups. Each committee is comprised of managerial and high-level technical representatives from the Regional Councils.

The two principal committees of NERC, the Engineering and Operating Committees, report to the Board of Trustees and advise the Board on matters within their respective scopes. The scope of the Engineering Committee is defined by its mission which is "to promote the reliability and adequacy of the North American bulk power supply as related to the planning and engineering of electric systems, and to provide a mechanism for coordination of activities in the areas of planning and engineering." The scope of the Operating Committee is defined by its mission which is "to promote the reliability and adequacy of the North American bulk power supply as related to the operation of electric systems, and to provide a mechanism for the coordination of interconnected system operation" ("NERC Organizational Structure of Technical Committees, Approved by the Board of Trustees January 11, 1984", Appendix R-1, p. 39).

Current subgroups of the Engineering Committee include the Interregional Review Subcommittee, the Reliability Criteria Subcommittee, the Load Forecasting Working Group, the Multiregional Modeling Group, the Generating Availability Data System Regional Advisory Working Group, the Generating Availability Trend Evaluations Working Group, the Fossil Design Review Task Force, the Capacity and Demand Determination Task Force, the Electromagnetic Pulse Working Group, the Load Forecasting White Paper Task Force, the Engineering Committee Review Task Force, and the Cogeneration Task Force.

Current subgroups of the Operating Committee include the Interconnected Operations Subcommittee, the Operating Reliability Subcommittee, the Performance Subcommittee, the Disturbance Analysis Working Group, the Monitoring Working Group, the Interconnection Dynamics Task Force, the General Meeting Working Group, the Parallel Flows Task Force, and the Criteria and Guides Review Task Force.

The membership of each of these subgroups is presented in the 1986 Annual Report of NERC.

ECAR

Criteria for voting membership in ECAR are:

1) ownership of an electric utility system engaged in the generation, transmission, and sale of electric power in the East Central area;
2) direct or indirect interconnection and operation in synchronism with two or more members in the Agreement; and
3) having a significant impact on reliability.

Non-voting (liaison) members are those systems not having a significant impact upon reliability but sharing concerns relating to the reliability of bulk power supply.

The Executive Board is responsible for the general administration and supervision of ECAR. Each bulk power member is represented on the Executive Board and appoints its own representative. Decisions of the Executive Board require the affirmative votes of members whose non-coincident peak loads for the previous calendar year aggregated at least 95% of the total non-coincident peak load of all parties to the ECAR Agreement.

The Liaison Committee provides a means whereby smaller electric utilities in the region which do not make a significant contribution to reliability inform the ECAR Executive Board of matters of mutual interest and concern, and are informed of ECAR activities and plans. It consists of one representative from each state (elected by members within each state) for a total of eight, one representative elected by the municipal utilities of each state (8), one representative of each states Utility Commission (8), and one representative of the Federal Power Commission. The Liaison Committee meets bi-annually.

The Coordination Review Committee is composed of a representative of each bulk power member. This Committee is responsible for the analysis of all matters affecting the reliability of bulk power supply, including the development of sound practices and principles to be presented to the Executive Board for adoption by ECAR members. It monitors the application of adopted practices and evaluates their results.

Eight Advisory Panels, each limited to seven members, assist the Coordination Review Committee in carrying out its responsibilities. Panel members are appointed by the Coordination Review Committee and approved by the Executive Board. Advisory Panels may appoint small working groups of three or more members to carry out specific assignments as needed.

The Transmission System Performance Panel (TSPP) assists the Coordination Review Committee in carrying out its duties in the area of transmission system performance and evaluations. Its current activities are listed on page 156 of Appendix R-1. The other seven Advisory Panels assist the Coordination Review Committee in the areas of Electric Equipment, Generation Facilities, Operation, Transmission Facilities, Environmental, Generation Resources, and Protection.

ECAR is represented on the Joint Interregional Review Committee (JIRC), which carries out the intent of coordination agreements between ECAR and NPCC, between NPCC and MAAC, and among VACAR (a subregion of SERC), ECAR and MAAC. JIRC membership consists of one representative each from ECAR, MAAC, NPCC, and VACAR. JIRC has established two study committees, MEN (MAAC-ECAR-NPCC Regions) and VEM (VACAR-ECAR-MAAC Regions), to engage in activities consistent with the intent of the coordination agreements.

MEN and VEM report to JIRC and conduct the necessary periodic analysis and review of generation and transmission expansion programs. The goal of these studies is to provide assurance that system developments and operating procedures within each region are being properly coordinated so they do not adversely affect other regions. An Executive Manager's Office performs ECAR's day-to-day functions and coordinates ECAR's activities.

ERCOT

All members of ERCOT are voting members. Membership is open to any entity, corporate or otherwise, which owns, controls and operates an electric power system in Texas. An electric power system consists in part (or all) of facilities for generation, transmission, or distribution of electricity in intrastate commerce only. Membership is extended to federal agencies, federally owned or financed systems, state power authorities, municipals, investor-owned utilities, and rural electric cooperatives.

Votes of members are weighted on the basis of the average number of kWh handled through the intrastate system for the preceding three calendar years. Voting strength is determined by multiplying 1000 times the ration of average kWh handled to total average kWh handled for all members. Each entity is assured of a minimum of one vote.

The Executive Board consists of 13 chief executives of member systems. All segments of the industry are represented on the Executive Board, which consists of at least six representatives of investor-owned utilities, two representatives of municipal systems, one representative of state power authorities, and two representatives of rural cooperative systems. These representatives are appointed by majority vote of the Council members of the types of system specified. Two additional members are elected by a majority vote of Council members. The Technical Advisory Committee provides guidance and technical support to the Executive Board. It also supervises and approves the work of three permanent subcommittees, the Engineering, Operating, and Environmental Subcommittees.

The Engineering Subcommittee performs, evaluates and reviews basic system studies. It also reviews and recommends planning criteria for Technical Advisory Committee approval, and carries out studies essential for continued system adequacy and dependability. The Operating Subcommittee, with Technical Advisory Committee approval, prepares the operating guides establishing operating procedures and responsibilities of ERCOT members. The Environmental Subcommittee monitors system operation for compliance with existing regulations and reviews proposed legislation.

Specific Subcommittee functions are set forth in Article VII-A of the ERCOT Agreement.

According to NERC's "1987 Reliability Assessment", three task forces were created during 1986 to address reliability related issues. A Communications Task Force was created to evaluate the availability of existing communication systems in the event of an ERCOT blackout. The Black Start Task Force was created to develop overall restoration procedures in the event of a Regional blackout. An additional task force was created to evaluate the adequacy of ERCOT's spinning reserve criteria (p. 52).

MAAC

The signatories to the MAAC Agreement plan and operate their bulk power systems as an integral part of the Pennsylvania, New Jersey and Maryland Power Pool (PJM). Thus, MAAC's organization, functioning and procedures are significantly influenced by the requirements of formal power pool coordination.

Voting members of MAAC must meet three criteria. They must be directly interconnected and operating in parallel with one or more MAAC members; their operations must significantly impact the reliability of the bulk electric supply systems of MAAC members; and they must abide by the rules of the Executive Board.

Non-voting members (associates) may include any municipal systems, rural electric cooperatives, or small investor-owned utilities which are served by MAAC members and agree to the principles of the MAAC Agreement. Associate membership is limited to fifteen: one each of representatives for a) municipals for each of the five states in which MAAC systems operate; b) small investor-owned utilities for each of the five states; and c) rural electric cooperatives for each of the five states.

The Executive Board consists of one representative for each voting member (except that there is only one representative for the three GPU-owned subsidiaries). Decisions of the Board require votes by representatives whose collective previous year's peak loads represent 95% of total peak load for the previous year.

The Area Coordinating Committee (ACC) is charged with the continuing review of the principles, procedures and standards in use, the review of each participant's plans for generation and transmission, and other matters of the reliability of MAAC bulk power electric systems as set forth in Article 4 of the Agreement. The ACC reports to the Executive Board.

Although the Executive Board may appoint additional committees as it requires, there are none currently.

MAIN

Voting (regular) membership is open to all original signers of the MAIN Agreement (except one original signer which is an associate member), and to any other power supplier 1) with a 115 kV or higher interconnection with a regular member, 2) whose operations have a significant impact upon reliability, and 3) who undertakes the obligations of the Agreement.

Non-voting members (associates) include Soyland Power Cooperative, an original signer, and any municipal or small electric system operating in MAIN but not meeting the above criteria.

Regular members each have one vote, plus one additional vote per 100 MW of peak load for the previous year, to a maximum of 40 votes. A quorum is comprised of a majority of the total votes in MAIN; and a majority of votes cast with a quorum present will adopt proposals.

Regular members are assigned to four areas: Commonwealth Edison, Union Electric, South-Central Illinois, and Wisconsin-Upper Michigan. The Executive Committee is composed of one representative from each of the four areas.

Standing and ad hoc committee members are designated by the Executive Committee, and associates are not specifically excluded from committee membership.

The Economy Transfer Study Task Force of the Operating Committee is charged with identifying specific factors, evaluating alternatives, and making recommendations regarding economic aspects of multilateral interchange.

MAPP

MAPP operates as a formal power pool. Conditions of participation set forth in its Agreement reflect the requirements of formal power pool coordination.

Voting members of MAPP (participants) are electric utility entities which: 1) own/lease and operate one or more generating units and which operate those units to meet all or part or system load; and 2)(whose system is directly interconnected with one or more participants at a level sufficient to meet the obligations of the Agreement; and 3) which operates or participates in a 24-hour dispatch center with a terminal on the MAPP communication network;

and 4) which maintains during each month Accredited Capability (net generating capability plus purchased power excluding economy energy, minus commitments) equal to or greater than its maximum system demand plus reserve capacity obligation.

Non-voting members (associate participants) may include any electric utility entity meeting the above criteria but not wishing to be a participant, or any electric utility not meeting the above criteria. Associate Participants may act as non-voting members on all MAPP committees except the Design Review Committee and the Area Relations Committee.
There are 27 Participants, 15 Associate Participants and 1 Liaison utility in MAPP.

The Management Committee consists of one representative per participant and one representative per associate participant, although the latter do not vote. The voting strength of Management Committee members is based upon system demand, with one vote allotted for each 25 MW (plus fractions) up to 300 MW, one vote for each 50 MW (plus fractions) between 300 and 600 MW, and one vote for each 100 MW (plus fractions) over 600 MW. A majority of total votes is required for action.

The Management Committee supervises the development of plans and procedures to attain Agreement objectives, specifies the duties and authority of the Engineering, Operating, Design Review, Environmental, Area Relations, and other Committees, which duties and authority are not set forth in the MAPP Agreement, and reviews and approves recommendations of the Design Review Committee. Other duties of the Management Committee are specified on pages 43-44 of Appendix R-1.

The Engineering Committee, under direction of the Management Committee, administers the planning and design reliability functions for bulk power supply pursuant to the MAPP agreement. It establishes and revises as necessary design reliability standards for the bulk power supply of MAPP, and coordinates such standards with regional power coordinating groups. Other specific duties of the Engineering Committee are listed in Article X of the MAPP Agreement (Appendix R-1, pp. 44-45).

The Operating Committee, under direction of the Management Committee, is responsible for establishing practices, rules, and procedures to coordinate the operations and pool energy accounting of the bulk power generation and transmission facilities of MAPP utilities. Specific duties of the Committee are listed in Article XI of the MAPP Agreement (Appendix R-1, pp. 45-46).

The Design Review Committee with the assistance of the staff of the MAPP Coordination Center and in conjunction with each Participant is responsible for reviewing and evaluating each utility's planning for generation and transmission facilities for conformance to reliability design standards established by the Engineering Committee, and reporting findings to the Management Committee. Under Article XII of the MAPP Agreement, the Design Review Committee is empowered to approve any operating restrictions necessary to make a Participant's planned facilities operate within MAPP reliability design standards.

NPCC

Information of NPCC organization provided in the Survey Response was limited, due to the inclusion of only pages 2 and 4 of the NPCC Agreement, and the omission of several attachments. No information was provided on membership or voting criteria.

The 1986 Annual Report of NERC provides some information on NPCC organization. It states that " NPCC consists of 22 full members... Member systems in New England are also members of the New England Power Pool, and member systems in New York are members of the New York Power Pool. New Brunswick Power, Nova Scotia Power, Ontario Hydro, and Hydro-Quebec are single entities serving their respective provinces in Canada.

"Membership in NPCC is available to electric systems '...which, by virtue of generating or transmission capacity, or concentration of load, can have a substantial effect on the service reliability of the Northeast interconnection.' The Council's Memorandum of Agreement also provides for a non-voting associate membership classification" (p. 48).

The Executive Committee of the Council consists of the Ex Officio Chairman and Vice-Chairman of the Council, acting as Chair and Vice-Chair of the Executive Committee. Additional members are designated by the Chairman to represent "all major operating areas.

The 1986 Annual Report of NERC provides an organization chart for NPCC. Three standing committees include the System Design Coordinating Committee, the Public Information Committee, and the Operating Procedure Coordinating Committee. Five task forces report to the System Design Coordinating Committee: these are the Task Force On Load and Capacity, the Task Force On Coordination Of Planning, the Task Force On System Studies, the Task Force On System Protection, and the Task Force On Environmental Matters. Three Task Forces report to the Operating Procedure Coordinating Committee: these are the Task Force On On-Line Computers, the Task Force on Fuels, and the Task Force On Coordination Of Operation.

SERC

Voting membership in SERC is open to any power supply entity operating or responsible for operating facilities connected to the interconnected power system, which is located in the area of SERC members and which provides bulk power supply with a normally connected generating capacity of 25 MW or more. Non-voting membership for systems connected with a SERC member system but providing less than 25 MW is open to up to four representatives on a sub-regional basis for each of two categories: 1) municipal or other publicly-owned systems and 2) rural electric cooperatives. SERC's four subregions are Florida, Southern, Tennessee Valley Authority, and Virginia-Carolinas (VACAR). Candidates for non-voting membership are nominated by the entities of each category and are selected by the Executive Board.

The Executive Board is composed of one representative for each member. Voting is proportional to installed generating capacity. Action by the Board requires ninety percent of total voting rights.

Prior to 1986, SERC had one standing committee, the Technical Advisory Committee. It is now known as the Engineering Committee. In 1986, the Executive Board approved the formation on the Operating Committee. The Engineering and the Operating Committees each consist of a member and an alternate from each member system. The Operating Committee has an affiliate membership for systems which are not members of SERC.

The Reliability Review Subcommittee is a permanent subcommittee of the Engineering Committee. The Subcommittee monitors reliability matters, reviews planning criteria, and develops information for reports.

The Communications Subcommittee is a permanent subcommittee of the Operating Committee. It is responsible for keeping informed on communication matters and developments of interest to system operations.

SPP

Voting membership in SPP is open to any system, interconnected at 115 kV or above with an SPP member, which:

1) owns and controls a 115 kV or higher transmission line in synchronous operation and with an installed total capability of 100 MW or greater;
2) owns or controls not less than 300 MW of installed generating capacity with the SPP area;

3) makes a significant contribution to overall reliability in SPP through its power supply and transmission system;
4) generates on a 24-hour basis with its own installed or controlled generating capacity; and
5) has a 24-hour dispatch center or has contractual arrangements with a load control area to fulfill that function.

Non-voting (associate) membership is open to electric utilities which serve 25 MW of load and control not less than 25 MW of operable generation, and which are in synchronous operation of a transmission interconnection with a member of SPP.

Voting strength is calculated quarterly on the basis of fees assessed SPP members. It is determined by multiplying 1000 times the ratio of a system's total assessment for the preceding four quarters to the total assessment of all SPP members for the preceding four quarters, where a quarterly assessment is equivalent to the total current quarterly assessment of members times the ratio of the member's maximum clock hour integrated MW demand during the preceding calendar year to the total members' maximum clock hour integrated MW demand for the preceding calendar year.

The Board of Directors consists of 16 member representatives, including at least three representatives of non-investor-owned utilities.

The Engineering and Operating Committee consists of one representative from each voting member, as designated by the member. This committee is responsible among other things for recommending practices for system operation that will help assure reliable bulk power supply among systems in the SPP region; coordinating its efforts with NERC; studying Members' operating plans and problems pertinent to the SPP Agreement; suggesting matters for study by the Members; reviewing results of studies submitted to it; developing and recommending to the Board of Directors reliability criteria for intraregional planning; and encouraging the adoption of reliability criteria for inter-regional planning.

Subcommittees of the Engineering and Operating Committee address issues of Transmission and Planning; Load Forecast/ Reserve Capacity; Operating; Communication; Reliability Criteria; Intraregional-Interregional Affairs; SPP-NERC Interregional Review; and Tie Line-Load Regulating.

WSCC

Membership of WSCC is open to any electric utility or group of utilities or organizations which are involved in planning and/or operating of its member utilities, regardless of the type of facilities owned or operated and regardless of system size. Voting membership is available to entities with generation in excess of 100 MW or transmission above 230 kV. The Council consists of one representative per member system.

The Executive Committee is responsible for directing and coordinating the Council's activities. It is composed of Officers of the Council (Chairman, Vice-Chairman, Secretary-Treasurer), twelve representatives of members of the Council who are elected by the majority of Council members, and the immediate Past Chairman. Officers of the Council and the immediate Past Chairman comprise the Administrative Committee, which is responsible for implementing the directives of the Executive Committee and conducting the day-to-day affairs of the Council.

Other Committees are open to all members; affiliates may attend but not cast votes. Four standing committees carry out the technical activities of the Council: Operations, Planning Coordination, Public Information, and Environmental. Numerous Subcommittees, Work Groups and Task Forces complement the Committee structure.

The Planning Coordination Committee is responsible for accumulating necessary data and performing regional studies of the operation of the interconnected systems necessary to determine the reliability of the western regional bulk power network. It formulates reports and recommendations based on these studies and presents them to the Executive Committee. Its recommendations include system design criteria for the guidance of Member systems. system disturbance reports compiled by the Operations Committee are reviewed annually by the Planning Coordination Committee to analyze system performance relative to WSCC design criteria.

The Operations Committee is responsible for reviewing and analyzing operating procedures and problems relating to the reliability of the operations of the interconnected bulk power systems and such problems as may be referred to it by the Executive Committee. It may recommend to the Executive Committee new or modified operating policies and procedures for the guidance of the member utilities as may be required to improve reliability of the interconnected bulk power systems. Duties of the Public Information and Environmental Committees are set forth in the WSCC
Agreement.

WSCC is subdivided into four areas: the Northwest Power Pool Area, the Rocky Mountain Power Area, the Arizona-New Mexico Power Area, and the California-Southern Nevada Power Area.

RELIABILITY COUNCIL DEFINITION, MEASUREMENT, AND ANALYSIS OF GENERATION AND TRANSMISSION RELIABILITY

NERC's "Reliability Concepts in Bulk Power Electric Systems" presents a useful definition of reliability. "*Reliability*, in a bulk power electric system, is the degree to which the performance of the elements of that system results in power being delivered to consumers within accepted standards and in the amount desired." It can be addressed by considering two basic and functional aspects of the bulk power system -- adequacy and security. "*Adequacy* is the ability of the bulk power electric system to supply the aggregate electric power and energy requirements of the consumers at all times, taking into account scheduled and unscheduled outages of system components. *Security* is the ability of the bulk power electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components" (Appendix R-1, pp. 237-238).

NERC's "Reliability Concepts in Bulk Power Electric Systems" explains that reliability is measured with probabilistic and deterministic means in the electric utility industry. "'Deterministic' reliability criteria are desired responses to system disturbances. For example, a system must withstand an outage of any single system element without significant interruption of service. Different system developments will withstand disturbances more or less successfully. A statement that installed generation must be a specified percentage greater than the expected maximum demand is another example of a deterministic criterion...'Probabilistic' methods use reliability characteristics of system components to predict the likelihood that all of the demand will be served. Different system developments will have a higher or lower probability that all of the demand will be served" (Appendix R-1, p. 236).

While most electric utilities employ probabilistic methods to assess generating reliability, the assessment of transmission reliability "is almost wholly restricted to deterministic methods. The uncertainty of data regarding failure rates or availability of transmission components has hampered the implementation of probabilistic assessment techniques. There has been recent progress, however, and the movement toward probabilistic assessment of transmission system reliability appears to be gaining strength" (Appendix R-1, pp. 250-251).

Several documents submitted in response to the Regional Reliability Council survey address issues of the determination of generation and transmission reliability. The following summary discussion is taken in large part from "Overview of Planning Reliability Criteria of the Regional Reliability Councils of NERC, December 1987" (Appendix R-1, pp. 70-95) and from "Reliability Concepts in Bulk Power Electric Systems" (Appendix R-1, pp. 235-258).

Responsibility for the Development of Planning Criteria

Responsibility of the various entities within NERC for the development of reliability criteria and planning guides to be used in the planning of the interconnected bulk power electric systems of North America have been delineated by the NERC Board of Trustees. While the NERC Engineering Committee is responsible for developing Planning Guides which describe good practices for bulk power system planning, the Regional Councils, Subregions, Pools and/or the Individual Systems develop reliability criteria applicable to their region or area. The latter bodies are also responsible for arrangements to assure the interregional effects on reliability are reviewed. "The criteria and guides developed at all levels are reviewed at appropriate intervals by the originating entity and modified as appropriate" (Appendix R-1, p. 71).

System criteria are criteria used by individual utilities, or other entities which have financial responsibility for commitment of new facilities, in planning facilities or assessing plans. These criteria include methodologies for testing and measuring system performance and may include indices of satisfactory performance. Regional council criteria are criteria applied within a Council to assess the interaction of individual utilities for the bulk electric system facilities within the Council. These criteria include methods and procedures for rating generating units and other facilities, data systems and intersystem protection philosophies, and the specification of simulated tests to be performed. In some cases these activities are carried out as a function of an area or subregional group within a Regional Council, in which cases these would be area or subregional criteria.

"Reliability can be addressed by considering two basic and functional aspects of the bulk electric system -- adequacy and security...Adequacy [is] the ability of the bulk electric system to supply the aggregate electrical power and energy requirements of the consumers at all times, taking into account scheduled and unscheduled outages of system components...Security [is] the ability of the bulk electric system to withstand sudden disturbances such as electrical short circuits or unanticipated loss of system components" (Appendix R-1, pp. 73).

In its answer to Question 4a, NERC states that "the ultimate responsibility for acceptance of criteria must, of necessity, rest with the individual utility systems since they bear the ultimate responsibility for compliance with the criteria" (Appendix R-1 p. 182).

Assessment of Generation Adequacy

Council approaches to the assessment of generation reliability differ in accordance with differences in the structural relationships between the Regional Councils and their member systems, and in the degree to which the various approaches are formalized by incorporation into written documents. However, nearly all regions employ a probabilistic approach to generation adequacy analysis, by making direct probability assessments or by identifying an equivalent percent capacity margin. The industry standard of 1 day in 10 years loss of load probability (LOLP) is widely shared, but nowhere in the materials supplied in response to the Regional Reliability Council survey was there presented a justification for the choice of the standard, in economic or any other terms. Appendix R-1, Exhibits 1, 2, 3, 21, 22 and 23 (pp. 58a, 60a, 60b, 80a, 80b and 80c) summarize information concerning Council assessments of the rating and adequacy of generating capacity.

Variations in important parameters have significant effects on generation adequacy assessment. Among such parameters are rate of demand growth, demand shape, weather sensitivity, potential slippage of in-service dates, and fuel and unit availability.

Compatibility of data and methodology is appropriate within a region in three basic areas. In regard to demand characteristics, most regions encourage the use of a "normal" weather parameter in demand determination. Demand diversity is also taken into account where appropriate. In regard to capacity characteristics, all regions have a formal requirement for establishing the rating of generating capacity, and all regions (at one level or another) use either a probabilistic or judgmental evaluation of the effects on adequacy of operational availability rates of capacity.

ECAR

The Generation Resources Panel of ECAR annually assesses projected generating capacity margin for ECAR as a system. Assessment results cannot be applied to any individual member system or subregion within ECAR. Future capacity adequacy is measured by "Dependence on Supplemental Capacity Resources" (DSCR). The term refers to reliance on emergency support from outside ECAR to avoid the curtailment of firm load. The range of DSCR values deemed acceptable is annually reviewed by ECAR within the context of actual, recent operating experience and in the context of perceived assistance potentially available from other regions. Currently, DSCR values between 1 day and 10 days of each year of the study period are considered to constitute marginal but satisfactory bulk power supply adequacy.

ECAR uses conventional probability methods to determine DSCR values, taking into account forced full and partial generating unit outages and scheduled maintenance. No value for emergency support from outside systems is included.

In the event of an assessment of inadequacy, there is no provision made within the ECAR Agreement for specific action to be taken by a member company.

ERCOT

Adequacy of generating capacity in ERCOT is determined in relation to a regionally installed generation reserve of 15% over the forecast annual peak load. Currently, each system provides at least 15% reserve, equivalent to 13% capacity margin. ERCOT does not incorporate the effects of interconnections to systems outside the region. Its assessment qualitatively considers the effects of fuel availability, generating unit unavailability and operational requirements.

While members have agreed to design their respective systems to meet the regional criterion, there is no penalty for not doing so.

MAAC

Adequacy assessment is carried out in conjunction with PJM pool capacity planning and development of capacity commitments. The overall criterion of adequacy is an LOLP of 1 day in 10 years. Calculations take into account load forecast uncertainty, forced, maintenance, and planned outages, and emergency capacity support from outside systems. Assessed qualitatively are other events such as fuel shortages, deviations from load forecasts, slippages of capacity addition schedules and large scale capacity curtailments.

Members which fail to meet their installed capacity obligation are subject to financial penalties. Installed capacity obligations are determined with the consideration of systems' load characteristics and generator outage rates.

MAIN

MAIN employs a basic criterion of a regional LOLP of 1 day in 10 years. The calculations incorporate random forced full and partial outages, scheduled maintenance, capacity support from neighboring regions, and load forecast uncertainty. MAIN studies have determined that each system should maintain a minimum reserve margin of 15% to 20% (capacity margin of 13% to 16.7%) to meet the regional LOLP criterion.

There is no contractual agreement in MAIN that obligates member companies to build or own certain generating facilities nor are there specified penalties for not doing so.

MAPP

MAPP is a formal power pool. Conventional probability methods are utilized about every two years to assess generating reliability. Annual peak diversity is taken into account, and effects of variations in parameters is made, e.g. generating unit availability, load forecast, fuel availability and massive curtailment of capacity. For administrative purposes, generation adequacy in MAPP is based on each system maintaining, each month, a capacity margin of 13% (9% for hydro systems), which is equivalent to a 15% reserve margin. MAPP is currently evaluating the merit of including capacity assistance from adjacent regions when selecting the capacity margin which will provide appropriate reliability.

The MAPP Engineering Committee is charged with the periodic review of the generating reliability criterion.

Members have a contractual financial responsibility to carry a specified installed capacity.

NPCC

NPCC conducts reviews of analyses conducted by its subregions. Each subregion must document that it conforms in each future year to a criterion of 1 day in 10 years LOLP. Subregional assessments qualitatively assess fuel shortage, load forecast uncertainty, and capacity schedule slippage. The basic regional evaluation method is the LOLP method recognizing random full and partial outages, scheduled maintenance and reserve sharing from neighboring systems. Some member systems of NPCC use other probabilistic methods for their internal analyses, but these have been shown to be equivalent to or better than 1 day in 10 years LOLP.

SERC

Adequacy assessments in SERC are conducted at the system level under arrangements predating the establishment of SERC. Review and coordination of these assessments is performed by the Reliability Review Subcommittee.

Each individual system in SERC is responsible for installed capacity that is reasonable and appropriate for its specific situation, and is sufficient so that no system will unduly burden another.

SPP

SPP identifies criteria for its member systems. Individual systems are to maintain minimum capacity margins of 15.25%., equivalent to a regional capacity margin of 16.7%. Alternatively, individual system adequacy may be demonstrated by a probability study showing a LOLP of better than 1 day in 10 years. Such study must consider random forced outages, scheduled maintenance, load uncertainty, and emergency support from neighboring systems. In the event the LOLP criterion is used, there is a specified minimum capacity margin of 13% for steam-based utilities and 9% for hydro-based utilities.

There are no contractual requirements nor penalties involved in not complying with the region's criteria. -

WSCC

Capacity assessments in WSCC are made on a system basis and on a (four) subregional basis. One or more of three specified criteria are to be met: 1) monthly reserve after maintenance must exceed the greater of the largest risk plus 5% of load responsibility, or a parameter which incorporates factors to equate hydro and thermal capacity; 2) monthly reserve after maintenance must be greater than the two largest risks; and 3) LOLP of 1 day in 10 years or a 0.90 probability of meeting all loads must be achieved. Qualitative assessments are made of transmission facility delays, capacity addition slippage, forecast error, fuel shortages and abnormal water condition prospects.

There are no contractual arrangements at the regional level providing for compulsory action of members to comply with adequacy criteria.

Assessment of Transmission Security

The security of transmission systems, i.e. their ability to withstand sudden disturbances such as electrical short circuits or unanticipated loss of system components, is tested by through simulations of system performance under specified contingencies. The following discussion presents the various Regional Reliability Councils' approaches to contingency testing. Councils may require the simulation of more probable and/or extreme contingencies to assess the security of their bulk electric supply systems. The approaches of the various Regional Councils to contingency testing are presented below. Appendix R-1, Exhibits 5, 6 and 7 (pp. 61a-61f) summarize the extreme contingency assessment practices of the Regional Reliability Councils.

More probable and extreme contingency testing enables the assessment of the general ability for systems to withstand more probable and very severe events and to determine the location of possible weaknesses in bulk electric systems. Typical extreme contingency tests include the loss of an entire generating station or transmission substation, loss of all transmission circuits on a common right-of-way, or loss of a major load center. Most systems rely on planning engineers to select the most severe fault locations to be tested. These tests also evaluate other conditions which may lead to the tripping of additional facilities, such as excessive power flows and unacceptable bus voltages.

ECAR

ECAR specifies more severe contingencies for simulation testing in its Document No. 1, "Reliability Criteria for Evaluation and Simulated Testing of the ECAR Bulk Power Supply Systems" (Appendix R-1 p. 159), which is reviewed annually by the Transmission System Performance Panel for possible revision. Performance standards for more probable outages are not specified, for these are not expected to lead to widespread cascading outages; they are the province of individual systems. ECAR tests at least annually to determine the regions FCITC in conformance with NERC guidelines. Semiannual appraisals are made for current summer and winter peak load conditions.

The ability of bulk power supply systems to conform with ECAR Document No. 1 is reviewed by the ECAR Transmission System Performance Panel. Deficiencies are noted by the Panel and the member system with the deficiency is asked to explain what remedial action will be taken.

ECAR Document No. 1 consists of a set of reliability criteria to be used as the basis for evaluation and simulated testing of the bulk power supply network to identify when planning or operating strategies are necessary to avoid uncontrolled, area-wide power interruptions under adverse credible conditions. The Document "represents the combined judgment of the ECAR members and includes, in addition to a listing of reliability criteria, a brief description of the underlying principles that serve as the basis for their development" (Appendix R-1, p. 159).

The basis for the selection of Reliability Criteria is provided on pp. 160-161 of Appendix R-1. Therein is stated that reliability in local areas is the responsibility of the individual ECAR members. It is also stated that ECAR members believe that..."the reliability criteria should serve primarily as a means to measure the strength of the systems to withstand the entire spectrum of contingencies that may or may not be readily visualized, rather comprise a detailed listing of probable disturbances...In view of this, the selection of reliability criteria is based not on whether the specific contingencies for which the system is being tested are themselves highly probable but rather on whether they constitute an effective and practical means to stress the system and thus to test its ability to avoid uncontrolled, area-wide power interruptions under adverse credible conditions."

ECAR Document No. 1 lists the basic bulk power supply planning principles to which strict adherence is advisable to prevent area-wide power interruptions.

The Document also lists nine specified criteria for use in simulated testing. These are presented on pp. 162-163 of Appendix R-1.

Appendix R-1, Exhibit 26 (p. 86a) summarizes ECAR's approach to contingency assessment.

ERCOT

ERCOT's "Planning Criteria" requires simulated testing and identifies several contingencies to be used in such testing. The ERCOT Engineering Subcommittee of the Technical Advisory Committee annually reviews adequacy in accordance with the ERCOT Planning Criteria and notes deficiencies which are brought to the attention of those responsible. Resolution of unacceptable test results is up to the utilities involved. ERCOT did not submit "Planning Criteria" among the materials responsive to the Reliability Council survey.

ERCOT more probable contingency assessment criteria are presented in Appendix R-1, Exhibit 8 (p. 64a). ERCOT's approach to contingency assessment is presented in Appendix R-1, Exhibit 27 (p. 86b).

MAAC

The "Reliability Principles and Standards for Planning Bulk Power Electric System of MAAC" (Appendix R-1, p. 164) requires system planning and construction to insure operation so the more probable contingencies can be sustained with no loss of load. The document specifies examples of more probable contingencies, along with system performance specified during those contingencies. Test criteria are also specified to determine transfer capability limits for emergencies as well as for extended period transfers.

Member systems proposing a change in the bulk electric system assess adequacy under extreme contingencies. The assessment is reviewed by the Area Coordination Committee (ACC) of MAAC before commitments for the changes are undertaken. If a proposed change would result in an adverse effect in the opinion of MAAC's Executive Committee after considering the recommendation of the ACC, the Council would recommend that alternative designs be considered. Implementation of the alternative plan is required if it is agreed that the associated benefits outweigh the additional costs.

"Reliability Principles and Standards for Planning Bulk Electric Supply System of MAAC" states that "the bulk power system shall be planned and constructed in such manner that it can be operated so the more probable contingencies can be sustained with no loss of load. Less-probable contingencies will be examined to determine their effect on system performance" (Appendix R-1, p. 164). The standards do not apply to facilities affecting the reliability of supply only to local system loads.

The unscheduled contingencies to be employed for MAAC system simulation are presented as Transmission Requirements on p. 165 of Appendix R-1. In addition, General Requirements regarding reactive load and loss requirements, and Stability Requirements are presented on pp.. 166.

This MAAC document also presents less probable contingencies to be used as examples of tests for the ability of MAAC to withstand abnormal disturbances. "These tests are prescribed not on the basis of a high level of probability, but rather as a practical means to study the system for its ability to withstand disturbances beyond those which can reasonably be expected" (Appendix R-1, p. 166). These are presented on pp. 166-167 of Appendix R-1.

This document also presents requirements for the installation of relaying and protective devices and for network power transfer limits, both extended period transfer and capacity emergency transfer.

MAAC more probable contingency assessment criteria are presented in Appendix R-1, Exhibit 9 (p. 64b). MAAC's approach to contingency assessment is summarized in Appendix R-1, Exhibit 28 (p. 86c).

MAIN

The Future System Study Group of the MAIN Transmission Task Force, under the direction of the MAIN Engineering Committee, assesses the bulk electric system under Extreme Contingencies. This is done in accordance with MAIN Guide No. 2, "Simulated Testing of the MAIN Bulk Power Transmission System". Any planned facilities not meeting MAIN Guide No. 2 are brought to the attention of member companies through studies and reports of the MAIN Transmission Task Force. Review of MAIN Guide No. 2 may be initiated by those applying the Guide or by issuance of a related NERC reference document.

Main Guide No. 2 presents the characteristics of a well planned bulk power system, and describes Transfer Capability and Extreme Disturbance testing for regional and subregional transmission system evaluation. Transfer Capability simulation guidelines are provided for FCITC, SCITC (a test "useful for disclosing possible weaknesses in the design of the transmission system and therefore may be considered in planning and operating the system), and IITC in accordance with NERC guidelines. A summarization of transfer capability testing measures is presented on page 172 of Appendix R-1.

Extreme Disturbance Testing is conducted such as to "thoroughly search out the maximum credible contingencies for examination with good assurance that the many possible contingencies not studied are less severe. The most severe contingencies to be studied are presented on pages 172-173 of Appendix R-1.

More Probable Contingency testing is done by MAIN to determine how first or second contingencies affect transfer capability.

MAIN's approach to contingency assessment is summarized in Appendix R-1, Exhibit 29 (p. 86d).

MAPP

The MAPP Design Review Committee is established for the purpose of reviewing system generation and transmission plans (additions and retirements) to assure compliance by the Parties with "System Design Standards". The Committee is not responsible for conducting appropriate system improvement studies in order to evaluate individual

Party plans.

It is the policy of MAPP that "additions which cause degradation of operations, reliability, or transfer capability will not be approved" (Appendix R-1, p. 189).

The MAPP Document, "System Design Standards", includes criteria for system performance and reliability for More Probable Contingencies. Reliability under Extreme Contingencies is assessed periodically by a MAPP subcommittee in accordance with System Design Standards.

If planned facilities will adversely affect system reliability, the member system can be refused accreditation in the Pool for the capacity addition. Failure to meet the extreme contingency test criteria will result in the member system being informed of the deficiency and required to correct it.

Party Transmission Capacity Requirements and Reactive Capacity Requirements are presented on pp. 191-192 of Appendix R-1. Probable Disturbance and Extreme Disturbance contingencies for simulated testing purposes are presented on pp. 193-194 of Appendix R-1. MAPP Operating Standards, Section #1 requires that each Party operate its system in such a manner to prevent interruption of load in the event of the Probable Disturbances listed on Page 192-193 of Appendix R-1 in "System Design Standards".

MAPP also cooperates in studies with the adjoining regions of MAIN and SPP and exchanges information for modeling with other NERC regions.

MAPP more probable contingency assessment criteria are presented in Appendix R-1, Exhibits 10-12 (pp. 64c-64e). MAPP's approach to contingency assessment is summarized in Appendix R-1, Exhibit 30 (p. 86e).

NPCC

"Basic Criteria for Design and Operation of Interconnected Power Systems" states that such systems should be designed with sufficient transmission capacity to serve area loads during and after specified More Probable contingencies. Area refers to New Brunswick/Nova Scotia, New England, New York, Ontario and Quebec. In addition, periodic reliability reviews are made of the overall NPCC interconnected, again with the view of conformance to NPCC criteria.

Extreme Contingency testing is conducted triennially by the NPCC Task Force on System Studies. Measures will be utilized where appropriate to reduce the frequency of occurrence of such contingencies, or to mitigate the consequences that are indicated.

NPCC did not provide "Basic Criteria for Design and Operation of Interconnected Power Systems" as part of the response to the Regional Reliability Council survey.

NPCC more probable contingency assessment criteria are presented in Appendix R-1, Exhibits 13-14 (pp. 64f-64g). NPCC's approach to contingency assessment is summarized in Appendix R-1, Exhibit 31 (p. 86f).

SERC

SERC Guide No. 3, "Criteria for Reliability in System Planning", is directed toward preventing cascading outages for the more Extreme Contingencies. More Probable Contingencies are addressed by member systems. The Reliability Review Subcommittee of the Engineering Committee annually reviews adequacy under extreme contingencies. The annual report "also provides an opportunity for SERC systems to express to the..[Engineering Committee]...and the Executive Board their concerns on current and future matters which may adversely affect the reliability of the bulk power system" (Appendix R-1, p. 176). The annual report comprises an assessment of the adequacy of reliability studies conducted by the four subregions, the coordination of such studies with other affected subregions or regions, and the ability of the planned systems to meet SERC Guideline Number 3. The Council role is limited to identifying problems and referring them to systems involved.

SERC Guideline Number 3 recognizes that local area reliability is the responsibility of individual SERC members and that each system has internal criteria relating to the more common contingencies. The objective of regional criteria is "to assure that the SERC bulk power systems are planned so that cascading outages will not result from any foreseeable contingencies. Contingencies identified which may result in cascading are: sudden loss of entire generating capacity in any one plant; sudden loss of a large load or major load center; and four transmission contingencies presented on page 180 of Appendix R-1.

SERC's approach to contingency assessment is summarized in Appendix R-1, Exhibit 32 (p. 86g).

SPP

SPP "Reliability Criteria" states that the generation and transmission systems of the SPP shall be planned and constructed so that the more probable contingencies will not result in a significant interruption of load. No one of these contingencies should cause the emergency rating of any equipment to be exceeded; the system shall be capable of being readjusted in a few minutes to bring all equipment within normal ratings. SPP states in its response to the Reliability Council Survey that..."Detailed contingency assessment criteria along with system performance goal descriptions are enumerated in Appendix 1" (Appendix R-1, p. 64H, Exhibit 15).

The less probable contingencies set forth on pages 202-203 of Appendix R-1 may result in interruption of load, but the situation is to be controlled so as not to result in cascading of interruptions.

Adequacy is assessed annually, or as needed, for the Group or Sub-area by the Transmission and Planning Subcommittee and submitted to the Engineering and Operating Committee for its information and review. There is no requirement for a periodic testing, however. Failure to design the system in accordance with Extreme Contingency design criteria will be discussed in the Pool meetings.

Bulk power system data banks for ten future years are updated annually.

Studies with adjoining regions are made as needed by either adjacent systems or by a special task force appointed for that purpose.

SPP more probable contingency assessment criteria are presented in Appendix R-1, Exhibit 15 (p. 64h). SPP's approach to contingency assessment is presented in Appendix R-1, Exhibit 33 (p. 86h).

WSCC

The Operations Committee is responsible for monitoring day-to-day operation and assessing anticipated near term operating conditions. It also recommends such operating procedures as affect the reliability of the interconnected bulk power systems of WSCC members. The Planning Coordination Committee is responsible for annually reviewing and assessing reliability of the interconnected system as currently planned for ten years in the future by the WSCC members. It recommends criteria for such elements of system design as affect the reliability of the interconnected bulk power systems. The criteria enumerated in "Power Supply Design Criteria" were developed by the Reliability Criteria for System Design Subcommittee of the Planning Coordination Committee. "Council and NERC criteria which have been adopted are used as a basis for evaluating and assessing system performance and system reliability" (Appendix R-1, p. 181).

The Reliability Subcommittee of the Planning Coordination Committee prepared the document, "WSCC Reliability Criteria for System Design". "Reliability Criteria for System Design" states that there should be no loss of load on a system for the more common single contingency disturbances originating on other systems. A single contingency is defined as the loss of a single system element under any operating condition or anticipated mode of operation. The most severe single contingency is defined as that single contingency which results in the most adverse system performance under any operating condition or anticipated mode of operation. In general, the WSCC Criteria is concerned with the impact of one Member System's planned facilities and power transfers on other systems. The permissible impact depends on the severity and probability of the disturbance. In this respect, the WSCC criteria are unique.

"In order to provide a level of performance consistent with the expectations of their customers and with system experience, individual systems or areas may adopt minimum design performance levels which differ from those presented herein" (Appendix R-1, p. 216).

"The bulk power systems will be operated at all times so that general system instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency...Multiple contingency outages of a credible nature will be examined, and the system will be operated to protect against general system instability, uncontrolled separation or cascading outages for these contingencies" (Appendix R-1, p. 217). The document "WSCC Minimum Operating Reliability Criteria" describes guidelines for operating reserve, automatic generation control, scheduling, transfer capability limit criteria, system monitoring, reactive supply and voltage control, and other topics under the heading of General Operating Criteria. Significant among these considerations are that systems or control areas shall determine normal transfer limits for the delivery or receipt of scheduled interchange, taking into consideration the effect of power flows through other parallel systems or control areas under both normal operating conditions and with a single contingency outage of the most critical facility. The operating criteria which the transfer capability limit must satisfy are listed on page 220-221 of Appendix R-1. The document also presents emergency operating reliability criteria.

WSCC more probable contingency assessment criteria are presented in Appendix R-1, Exhibits 16-19 (PP. 64i-64l). WSCC's approach to contingency assessment is summarized in Appendix R-1, Exhibit 34 (p. 86i).

JIRC

Severe contingencies to be utilized in the simulated testing of interregional power transfer among JIRC-associated Reliability Regions are presented in "Study and Testing Philosophy", an excerpt from the "Joint Interregional Review Committee Handbook" (Appendix R-1, pp. 183-184).

REGIONAL RELIABILITY COUNCIL ASSESSMENT OF TRANSFER CAPABILITY

Definition of Transfer Capability

Transfer capability is a measure of the ability of a transmission network to allow for the reliable movement of electric power from an area of supply to an area of need, expressed in MW. It is an indicator of system strength for the comparison of alternative system configurations. In essence, transfer capability is a reliability limit.

Transfer capability measures the ability to move power from one system to another. Measurement of non-simultaneous transfer capability between A and (B, C, and D) is done by simulating an A-B transfer, then an A-C transfer, and so on. Interdependencies of transfers among several parties would be taken into account to measure simultaneous transfer capability. Total usable import capability will be considerably less in most areas than the sum of non-simultaneous two-party transfer capabilities with surrounding areas.

"Transfer Capability: A Reference Document (October, 1980, NERC) is included in Appendix R-1 on pages 317-330. This document provides background material relating to transfer capability and recommendations in the areas of definitions and simulation techniques.

It is recommended by NERC that "First Contingency Incremntal Transfer Capability" (FCITC) be utilized by systems for general reporting purposes. It appears as though the NERC definition of FCITC (as well as other definitions provided by NERC in "Transfer Capability: A Reference Document") have been adopted by the Regional Reliability Councils. FCITC is "the amount of power, incremental above normal base power transfers, that can be transfered over the transmission network in a reliable manner, based on the following conditions: 1) with all transmission facilities in service, all facility loadings are within normal ratings and all voltages are within normal limits: 2) the bulk power system is capable of absorbing the dynamic power swings and remaining stable following a disturbance resulting in the loss of any single generating unit, transmission circuit or transformer; 3) after the dynamic power swings following a disturbance resulting in the loss of any single generating unit, transmission circuit, or transformer, but before operator-directed system adjustments are made, all transmission facility loadings are within emergency ratings and all voltages are within emergency limits. This definition is considered appropriate because some margin of transfer capability available must allow for additional power flows that will appear on transmission components when major facilities are forced out of service.

Definitions used for other purposes are provided for "second contingency incremental transfer capability" and "installed incremental transfer capability" (Appendix R-1, p. 322-323).

Definitions of "normal ratings", "emergency ratings", "normal voltage limits" and "emergency voltage limits" are found on page 323 of Appendix R-1.

The Document stresses that the capability of a network to effect energy transfers can be established only by measuring power transfer capability under a sufficient number of conditions.

Measurement of Transfer Capability

Simulation methods required to measure transfer capability require the judgmental prediction of many factors, including applicable operating procedures, load forecast, available generation, the geographic pattern of load generation, regional system configurations, and other power transfers in effect.

The derived value must represent a reasonable operating condition, conform with the requirements of transfer capability definitions, be unique for the particular situation being analyzed, and must consider the facility outages that result in conditions that are most restrictive to the system.
Receiving area generation outages are to be simulated so as to establish the most limiting conditions in the transmission system for the transfers being tested.

"ECAR/MAAC Interregional Power Transfer Analysis", a document prepared by the ECAR/MAAC Coordinating Group and included in Appendix R-1 on pages 299-316, states in regard to the use of transfer capability measurement that the "... comparison of transfer capabilities and limiting facilities over a period of time gives an indication of whether the overall strength of the bulk power transmission system is increasing, decreasing, or remaining about the same. A comparison of transfer capability and the potential need for economy transfer gives an indication of the magnitude of reinforcement desired. The location of the bottlenecks gives an indication of where the reinforcements are needed" (p. 308).

Reactive Power Limitations to Transfer Capability

The nature of ac current flow is such that not all current paths will reach their limits simultaneously. As increasing amounts of power are transferred across a system, an increasing amount of reactive power is required to support the system voltage. Areas of power deficit (e.g. a generator outage) require particular reactive power support. Thus, even at levels of power transfer which may NOT result in transmission facility overloads during single contingencies, voltage and reactive constraints may restrict power transfer.

NERC's "1987 Reliability Assessment" provides a definition of reactive power. "Reactive power is analogous to the more familiar active or real power, which is measured in watts. While active power is the means by which ac energy is supplied to perform useful work like running a motor or lighting an electric bulb, reactive power provides the important function of maintaining voltage -- and if an adequate voltage level is not maintained, active power or watts cannot be supplied. Reactive power thus provides the means by which watts can be transmitted to do useful work.

"A useful analogy might be made with dye used to color fabric. Real power can be compared to the pigment or tint; reactive power would then be the water with which the dye is mixed. The water doesn't color the fabric, but without it the pigment would not be able to do its job.

"Reactive power can be produced by generators and capacitors and by certain specialized devices such as synchronous condensers. In order to operate, reactive power is required by many customer loads -- such as large industrial machinery and the motors in refrigerators, air conditioners, etc. It is also consumed in transmitting electricity through transmission lines and transformers, just as real power is consumed in transmission losses. However, in virtually all transmission lines and transformers, reactive power losses greatly exceed the active or real power losses. Consequently, unlike active or real power, reactive power cannot be transmitted over long distances. As a result, reactive power must, to a large degree, be provided close to the point of use" (p. 29).

Appropriateness of Transfer Capability Values

"Transfer Capability: A Reference Document" states the following in regard to the appropriateness of a specific transfer capability goal. "There is no comprehensive and universally-applicable procedure for determining the 'appropriate' or 'proper' level of transfer capability beyond that needed for normal operation. Various techniques can be used to estimate the value of transfer capability in achieving specific system benefits and significant effort is being made to improve mathematical tools used for this purpose" (Appendix R-1, p. 326).

The Reference Document notes that the size of the power system being analyzed is a key consideration in the determination of a transfer capability goal. A large region may have sufficient diversity of internal resources coupled with a strong internal transmission system such that the value of import capability from outside could be quite small. Other important considerations include: reducing installed reserve requirements, flexibility to cope with uncertainties, economy energy transfers (short-term, non-firm basis to reduce operating costs), reduced generation investment costs, integration of power supply, sharing of regional resources (e.g. to overcome fuel shortages), and national goals.

"The concept of developing standards for transfer capability goals is elusive. Definitions and techniques can be specific, but the translation of these into goals must go beyond computer simulations to reflect less quantifiable, but important, considerations" (Appendix R-1, p. 330).

Transmission System Simulations Provided in Council Survey Responses

The Reliability Councils provided examples of transmission system simulations previously conducted in their responses to the survey questions. This Section provides a summary account of these simulations and their citations in Appendix R-1.

The MEN Study Committee conducted an appraisal of the MAAC-ECAR-NPCC (MEN) interregional system performance for conditions expected during the Summer 1986 period (Appendix R-1, p. 330). They used a linear transfer limit program, the New York Power Pool Contingency Analysis Program (CAP), to screen the transmission system modeled in the base case. This program is designed to linearly calculate thermal transfer limits between several regions. Since the program does not model reactive response, voltage limitations to transfers were examined using conventional AC load flow analysis. Rating criteria employed by MAAC, ECAR, and NYPP (NPCC) in the study are consistent with their own operating requirements and practices.

The VEM Study Committee conducted a similar appraisal of VACAR-ECAR-MAAC power transfer limitations (Appendix R-1, p. 335).

The ECAR/MAAC Interregional Power Transfer Analysis (Appendix R-1, p. 299), performed by utility representatives from ECAR and MAAC for the U.S.D.O.E. in June 1985, determined that the primary restriction to ECAR-MAAC transfers had been voltage conditions in MAAC and eastern ECAR (85% of time of transfer limitations, versus 15% for thermal conditions).

Additional specific studies of transfer capability referred to in the Reliability Council survey responses include the NPCC study of a planned 2000 MW export from Hydro Quebec to New England and the SERC 1985 "Cost Effective Oil Backout Study" by Florida Electric Power Coordinating Group, Southern, TVA and Fla. PSC.

Appendix R-1, Exhibits 49-52 present normal base power transfers and non-simultaneous FCITC values among the Regional Reliability Councils for Summer 1986 and Winter 1986-1987 (pp. 148a-148b, 155a-155b).

TRANSMISSION LIMITATIONS IDENTIFIED IN RELIABILITY COUNCIL RESPONSES

The Reliability Council survey responses provided numerous references to "transmission limitations", addressing the topic from a conceptual viewpoint as well as presenting specific instances of such limitations. This section of the report presents a summary of Reliability Council remarks on the subject of "transmission limitations".

Responses of the Reliability Councils to the NGA survey identified numerous sites where transmission of power is constrained.
Many of the specific limitations identified, however, may no longer be considered as such, since conditions have changed since the time of the survey responses. In any event, references to specific transmission limitations identified in the Reliability Survey responses are presented below.

NERC prepared a report in May, 1984 entitled "Impediments to Transfers: A Report for the National Association of Regulatory Utility Commissioners Committee on Electricity". The report is included in Appendix R-1 on pages 269-277, and presents a list of specific impediments to transfer of power (Appendix R-1, pp. 275-277). On June 5, 1985, NERC prepared "Impediments to Transfer: An Update", included on pages 278-283 in Appendix R-1. The update presents a listing of impediments that appear to have been resolved or eased since the publication of the initial report (Appendix R-1, pp. 280-281), and a listing of specific existing bottlenecks, impediments, or delayed facilities (Appendix R-1, pp. 281-283).

A presentation to the U.S.D.O.E. by the ECAR/MAAC Coordinating Group in June 1985 entitled "ECAR/MAAC Interregional Power Transfer Analysis" is included in the Appendix on pages 299-316. This report identifies bottlenecks constraining the transfer of power rom ECAR to MAAC at a time when a large disparity in fuel costs between the two regions provided a strong economic incentive to maximize such transfers. The report concludes that primary restrictions to transfers have been voltage conditions within MAAC and eastern ECAR. Parallel path flows resulting from power transfers effected by utilities in the Northeast are cited as another limiting factor.

Pages 108-110 of Appendix R-1 provide a list published in the "1986 Reliability Review" of NERC which identifies examples of specific projects that have been delayed because of regulatory actions. The 1986 Reliability Review identified specific transmission limitations and/or enhancements to overcome limitations for various of the Regional Reliability Councils. These include:

COUNCIL	SPECIFIC LIMITATION/ENHANCEMENT	APPENDIX R-1 CITE
ERCOT	Houston L&P 345 kV interconnection	119
	500 MW South Texas dc tie	119
	Zenith-Salem 345 kV interconnection	119
MAAC	Baltimore-Washington 500 kV loop	123
	MAAC West-East incremental power flow	124
NPCC	HQ/NEPOOL 2000 MW interconnection	129
	New England-New Brunswick tie line	129
	Marcy-South 345 kV reinforcement	129
	Mainland-Long Island 345 kV cable	129
	Seabrook-Tewksbury 345 kV line	130
	Bruce nuclear plant transmission	130
	Lennox Generating Station 500 kV lines	130
	Cornwall-Ottawa 500 kV line	130
WSCC	Increased capacity of dc Pacific Intertie	138
	Upgrading of ac Pacific Intertie	138
	Rifle-San Juan 345 kV line	138
	Wyoming/Colorado transmission paths	139
	Utah/Colorado transmission paths	139
	Four Corners to Central Arizona transmission	139
	Impact of remedial action schemes on Arizona-New Mexico power area	139

NERC also provided its 1986 Summer Assessment and its 1986-1987 Winter Assessment in response to the Reliability Council Survey, both of which are included in Appendix R-1. Respective appendix references to specific transmission limitations or enhancements to overcome such limitations which are not listed above are provided below:

REGION	SPECIFIC LIMITATION/ENHANCEMENT	APPENDIX R-1 CITE
ECAR	Belle River No. 2 circuit	143
	APS voltage conditions	143
ERCOT	Increased cogeneration deliveries from	

	Gulf Coast to North Texas	152
MAIN	Transfer capability from SPP and MAPP	145
	Minnesota-Upper Mich. transfer capability	145
SERC	Joppa-Shawnee-Paducah impact on MAIN to TVA interchange capability	147
	Reduced VACAR import capability	147
	Impact of power flows on SPP-SERC interface	154
WSCC	Colstrip generator tripping scheme	148

NERC's 1987 Reliability Assessment (September 1987), its 1987 Summer Assessment (June 1987), and its 1987/1988 Winter Assessment (November 1987) should be consulted to update this listing of specific transmission limitations and enhancements.

The effect of factors external to the PJM System (MAAC) on PJM utilities such as parallel path flows and non-PJM system operating problems are presented on page 263 of Appendix R-1.

RELIABILITY COUNCIL REMARKS ON RELIEVING TRANSMISSION CONSTRAINTS AND INCREASING TRANSMISSION EFFICIENCY

"Reliability Concepts in Bulk Power Electric Systems", a document prepared by the Reliability Criteria Subcommittee of NERC's Engineering Committee (Appendix R-1, pp. 235-259), delineates two different approaches for achieving reliability in bulk power supply systems. At one extreme is "a design philosophy in which highest quality components are selected and many redundant and parallel subsystems are used, with the intention of developing a very high system 'availability'. Speed of maintenance and restoration in that system would be less important because of the redundancy and the relatively rare occurrence of system failure....Alternatively, superb diagnostic instrumentation, tools and equipment, and personnel training and organization could be acquired and developed with the object of achieving very fast system restoration. Such a system will probably fail more frequently; however, this system would also be highly 'available' because of the speed with which it can be restored to normal operation....The preferred approach will undoubtedly lie between the two extremes just discussed, and will seek that combination of failure and restoration rates which results in acceptable reliability at the least cost, where 'cost' includes the consumers' costs due to not being supplied" (Appendix R-1, p. 239).

The following discussion first presents "System Design Features" broadly construed to include the incorporation of technical devices which facilitate the maintenance or restoration of normal operation. A summary of remarks on "Enhanced Computer Capabilities and Operator Training" employed in the industry to relieve transmission constraints and/or increase transmission efficiency is presented thereafter.

System Design Features

Specific system design features described in the Reliability Council survey responses include: automatic load shedding relays; means of controlling power flows such as 1) phase shifters 2) dc systems, 3) static var compensators, 4) Special Protection Systems (SPS), otherwise known as Remedial Action Schemes, 5) nominally-priced system upgrades, and 6) major ac transmission reinforcements; and generation location considerations.

Automatic Underfrequency Load Shedding Relays

Underfrequency relays are devices employed to drop load from a bulk electricity supply system in a declining frequency situation. Though most of the Reliability Councils have specific regional criteria covering this type of action, the need for such load shedding action is recognized in all Regions. Regional load shedding criteria are presented in Appendix R-1, Exhibits 39-45 (pp. 95a-95g).

Phase Shifters

Phase shifting transformers may be installed to control parallel flows by forcing such flows over alternative parallel paths. It is noted in the survey responses that the addition of phase shifting transformers in Southwestern Colorado to control loop flow is planned for 1988 (Appendix R-1, p. 137).

DC Systems

The effect of DC system installation is illustrated in "ECAR/MAAC Interregional Power Transfer Analysis", a document included in Appendix R-1. "Another transmission concept that would reinforce the ECAR/MAAC interface and thus improve transfer capability between the two regions is to integrate HVDC transmission into the easter interconnected transmission system. The use of HVDC offers a power flow controllability advantage, which provides a means of reducing the impact of power transfers on parallel AC network paths" (Appendix R-1, p. 309-310).

Static Var Compensators

Static var compensators are reactive power supply devices which prevent excessive voltage changes caused by power transfers. Their use allows transmission lines to be loaded closer to their maximum operational loading limits than would otherwise be possible. NERC'S 1987 Reliability Review states that "Since 1982, 2,381 Mvar of capacitors have been installed on the 230 kV and 500 kV systems [in MAAC] to improve transfer capability. The most recent addition, a 138 Mvar bank, was installed on the 500 kV system early in 1987. An additional 138 Mvar capacitor bank is scheduled for installation of the 500 kV system in 1987 (p. 56).

Special Protection Systems

NERC's "1986 Reliability Review" states that "Special Protection Systems are designed to perform system protection functions other that the isolation of electrical short circuits. They are used to automatically reconfigure the electrical system by disconnecting generation, opening lines, shedding load, and other actions to maintain stability or control power flows on surviving critical facilities immediately following a disturbance on the system. Special Protection Systems are installed to permit higher levels of power flow on the transmission system in those instances where additional facilities cannot be justified or built or have been delayed. However, they can expose a system to greater reliability risks, since the integrity of the system depends on their correct operation....

"SPS are complex and consist of a multitude of devices often at a number of locations geographically remote from each other. Due in large part to these characteristics, performance to date has not been as good as desired and some major outages have resulted. Improvement to such SPS applications is being pursued" (Appendix R-1, pp. 110-111.

It is noted elsewhere in the survey responses that special protection systems have been applied within Florida to force controlled separations or load shedding for certain multiple contingencies (Appendix R-1, p. 132). The WSCC states that it is evaluating alternative remedial action schemes which will confine the effects of disturbances involving...projects to the project participants, consequently minimizing the effects on neighboring systems" (Appendix R-1, p. 137).

In order to improve the reliability of the Pacific Intertie and associated remedial action schemes, NERC reports in its "1986 Reliability Review" that WSCC has taken several actions. "Relays and associated equipment are being replaced, additional circuit breakers and redundant communication systems are being added where appropriate and studies are being conducted to evaluate the addition of an independent detection scheme to initiate controlled islanding for loss of the ac Pacific Intertie should the primary transfer trip scheme fail" (Appendix R-1, p. 136).

Nominally Priced System Upgrades

The NERC document "Impediments to Transfers" remarks as follows in regard to low-cost means of upgrading transmission systems. "There is another concept held by many observers that there are little, inexpensive 'fixes' that can be made to the transmission system. The concept holds that these 'fixes' would open the flood gates to allow massive increases in transfers to take place. Several years ago, small improvements in jumpers [sic], sag restrictions, relay circuitry limits and such items were recognized as built-in, unnecessary limitations. After several years of operating in a heavy-transfer environment, it is reasonable to believe that no system would pass up the opportunity of making money from transfers by ignoring such easily-eliminated limitations. That is not to say that no limitations exist – the system is intended to have finite limits; but terminal modification, re-sagging and other recognized adjustments are being done continuously as the cost and benefit warrant" (Appendix R-1, p. 272).

Major AC System Reinforcements

"ECAR/MAAC Interregional Power Analysis" states in regard to the reinforcement of ECAR/MAAC interconnection with ac system additions: "One possible transmission reinforcement concept is the construction of a long distance EHV alternating current transmission which would be integrated into the existing EHV networks. Such a concept would continue the development of patterns that have been used in the past to strengthen the EHV networks of the area. To achieve a reasonable degree of improvement in transfer capability of the already well-developed EHV network would require a transmission addition with high loadability that is highly responsive to power transfers between ECAR and MAAC" (Appendix R-1, p. 309).

Generation Location Considerations

It is noted in the NERC Reliability Criteria Subcommittee's "Reliability Concepts in Bulk Power Electric Systems" that "Situations arise where either generation or transmission could be added to a system to meet reliability goals. Installing peaking generation near load centers can enhance the performance of a highly-loaded transmission system, for example" (Appendix R-1, p. 251).

Enhanced Computer Capabilities and Operator Training

Developments in computer capabilities and increased attention to operator training have resulted in the improvement of transmission system efficiency, according to the Reliability Council survey responses.

NERC reports in the "1986 Reliability Review" that several systems in ECAR..." are in the process of designing or constructing control centers that will incorporate system security procedures and analytical capabilities to provide operators with the ability to carry out on-line evaluation of system security. ECAR systems, in conjunction with the systems in MAAC, NPCC and SERC, are actively studying the concept of computer-to-computer data links for the exchange of real-time system data and to determine cost effectiveness. Implementation of such communication links could greatly expand the base of information available to evaluate on-line system performance, taking into account multi-system operating conditions" (Appendix R-1 p. 118-119). It also reports that..".[ERCOT] Enhancements to the SIS [Security Information System] included a sharing of cost data for economy transactions to be entered and viewed via control area terminals. Other enhancements included overhaul displays for coordinating unit maintenance and a load plot display for predicting daily peaks for control areas as well as for total ERCOT. Enhancements currently under development are accounting displays, transmission outage displays, ERCOT flow data base, and an interface between SIS and the operating load flow program" (Appendix R-1, p. 120).

"Since 1978, MAAC has participated with NPCC in a computer data exchange network for the instantaneous transfer of information among operating centers in these regions...NYPP, NEPOOL and Ontario Hydro, along with PJM, are also linked by a computer-to-computer communication system. Such multi-system monitoring on a real time basis greatly assists system operators in monitoring and controlling their systems, especially with regard to power transfers among numbers of parties and the resulting parallel path flow problems" (Appendix R-1, pp. 125, 130). The "1986 Reliability Review" also notes that utilities in SPP are installing similar state-or-the-art computer systems (Appendix R-1, p. 135).

Increased operator preparedness is required for efficient utilization of system information made available through computer technology. "With complex interchange effects...it is critical that system operators be well trained. Because the operators will be required to consider more options in the future before they make their operational decisions, operator training is being improved to include the use of new tools necessary to meet the complex challenges of the expanding electric systems. System restoration procedures also undergo frequent review and are an integral part of operator training" (NERC "1987 Reliability Assessment, p. 36).

UTILITY COORDINATION WITH RELIABILITY COUNCILS IN GENERATION AND TRANSMISSION PLANNING

Generally speaking, utilities coordinate their planning of generation and transmission facilities with their respective Regional Reliability Councils through the provision of information for the Councils' review of planned facilities' impacts on bulk electric supply reliability. The plans of utilities which are members of power pools which are also Regional Reliability Councils (MAAC/PJM, MAPP) are subject to the approval of the Pool or Council. Planned transmission line additions and upgrades are filed for the upcoming ten-year period with the U.S.D.O.E. by the Regional Reliability Councils are part of their IE-411 "Coordinated Bulk Power Supply Program" reports.

ECAR

ECAR appraises the aggregate plans of its member systems to assure that such plans are compatible and will satisfy ECAR reliability objectives. Member utilities report planned transmission projects to ECAR before they are undertaken and explain the purpose of the planned projects.

ERCOT

ERCOT evaluates major generation and transmission line additions with respect to their contribution to the maintaining of adequate resources for reliability of bulk power supply.

MAAC

The MAAC Agreement requires each signatory to report to the MAAC Executive Board their plans to add, modify, or remove facilities from the bulk power system as soon as possible after the plans have been approved by the signatory and to submit the results of engineering studies to establish that their plans meet the MAAC Reliability Criteria. Utilities are not required to provide a reason for their plans, but they generally do.

MAIN

Main Guides 2 and 6 provide for the consideration of major transmission line and generating unit additions within the region and in surrounding regions.

MAPP

Most planned transmission projects having regional impact involve generation additions as well; thus, they are presented to the Design Review Committee for review and approval before they are placed in-service and, in most instances before they are placed under construction. During the course of the Design Review Committee deliberation, reasons for the projects being undertaken are stated.

NPCC

NPCC's Memorandum of Agreements requires member systems to advise the Council of plans for new facilities and of changes to existing facilities. These notifications include the reasons for the system alterations.

SERC

There is no specific requirement that SERC members report planned transmission projects to the Council before they are undertaken. However, such information is made available to the Council staff at meetings of the Reliability Review Subcommittee, and is available annually as part of the Coordinated Bulk Power Supply Program.

SPP

SPP maintains and annually updates a bulk power system data bank which includes the planned transmission additions of member utilities for the upcoming ten year period. The Council does not evaluate the timing of generation unit and transmission system additions, but it makes member systems' plans available to all other members through annual reports and data bank updates.

WSCC

WSCC assesses the aggregate plans of member systems on a sub-regional and regional basis to assure that the proposed timing of each future facility will meet the Council's reliability criteria. It is the utility's responsibility to assess the timing for its facilities as compared to the other facilities being planned for the region. Utilities planning new or upgraded transmission facilities are required to provide an annual progress report for each new facility until the facility is placed in service. These reports are distributed to all members for review and include a description of the project and results of studies indicating the impact of the facility on the reliability of the interconnected system.

THE ROLE OF ECONOMICS IN RELIABILITY COUNCIL CONSIDERATIONS

The reliability criteria adopted by the Regional Reliability Councils and discussed in detail above are utilized by the Councils to assess potential reliability problems. A focus of the Reliability Council survey was the extent to which efforts to assess potential reliability problems include an evaluation of the potential for, and feasibility of, short- and long-term transfers of energy from low-cost regions to higher-cost regions. The survey asked how this potential was evaluated, and asked that specific cases or studies be cited in the survey response.

In general, the Reliability Councils are concerned with economics to the extent that it affects reliability of bulk power supply (See NERC's response on page 235 of Appendix R-1). However, differences in the organization of Council members, in particular their incorporation in a power pool, affect the extent to which economics is explicitly considered along with reliability in Council studies and deliberations.

This is not to say that economics is not implicit in all reliability considerations of the Councils. The NERC document "Reliability Concepts in Bulk Power Electric Systems" states that the goal of achieving a specified level of reliability is "to provide that degree of reliability with minimum total cost. 'Total cost' is the sum of the cost of the utility operations and the cost to the consumer of service interruptions. The latter cost is partially subjective and cannot yet be accurately measured" (Appendix R-1, pp. 235-236). "Economics is a vital part of all reliability considerations; providing reliability requires spending money" (Appendix R-1, p. 241).

In regard to generation reliability, the same document states that..."Research shows that the cost to the consumer does not change significantly for moderate increases from the minimum amount of planned capacity margin which will provide acceptable reliability. The impact on the consumer of unserved load due to having installed too little capacity may be very severe, however. Thus, installed generating capacity above that minimum needed for reliability may be good for the consumer in many systems" (Appendix R-1, pp. 236-237).

Consumer costs associated with reliability should be in accord with their own reliability expectations and their willingness to pay such costs. While in the past excellent reliability levels have been obtainable at low cost to the consumer, "that cost has increased dramatically in recent times because of inflation, environmental considerations and limitations placed on the expansion of the bulk power system" (Appendix R-1, p. 241).

In order to achieve capacity margins that will enhance the ability of bulk power systems to withstand disturbances,..."A balance must be struck between the costs of enhancing reliability and the consumer's willingness to pay. In striking this balance, the direct and indirect costs of supply failure must both be considered. These costs or lost values can be relatively obvious -- such as product loss or spoilage -- or subtle, such as the value of sustaining human life in a life-support situation, or the value of foregone comfort, recreation or entertainment..." (Appendix R-1, p. 241). These costs are conceptualized collectively as the "cost of unserved energy".

"The level of reliability that the bulk power system will ultimately achieve depends upon the utility's perception of what the customers will be willing to support financially....The utility must make a qualitative and indirect judgment of the appropriate level based on a combination of many factors, including feedback from the regulators and customers. Because any utility's customers are a diverse group of individuals, the judgment made by the utility reflects its perception of the consensus of that group" (Appendix R-1, p. 242).

The document also states that systems with poor reliability can initially increase reliability significantly with a relatively small investment, while systems with high reliability can usually increase reliability only slightly even with a large investment (Appendix R-1, p. 242-243).

The document states in regard to generating capacity margins that ..."Acceptable levels of reliability are somewhat judgmental, but they reflect a thoughtful cost-benefit evaluation. Figure 2 [Appendix R-1, Figure 53, p. 248a] is a graph of a relative reliability index as a function of generating capacity. The curve is for illustrative purposes and does not apply to any specific system or Council; however, the general nature of the curve is the same for all. Near the bend in the curve there are capacity levels above which there is little improvement in adequacy (benefit) for an additional increment in capacity (cost). On the other hand, there is a rapid deterioration in adequacy for small reductions in capacity" (Appendix R-1, p. 248). EPRI's Over/Under Capacity Program is cited as a technique which provides insight into the relationship of capacity margin to reliability and the economic tie between them. Appendix R-1, Figure 54, p. 248b, presents a representation of additional costs to customers due to deviating from the least-cost capacity margin level for two systems that participated in an EPRI Over/Under Capacity Program study.

Assessment of the adequacy of transmission facilities requires that transmission network capacity be compared with forecast load and network requirements. Assessment of the security of transmission facilities requires that such facilities be tested under simulated conditions of a variety of system disturbances. Hence, while transmission facilities may be deemed adequate in the sense that they provide sufficient capacity to deliver power and energy to load centers, the degree of security of such facilities in the event of system disturbances is a variable with economic consequences. Assessment of the costs of outages associated with degrees of system security is an extremely difficult task, given the "many possible failure modes of the transmission system, the great number of transmission system outages which do not result in any loss of continuity between generating source and the customer, and the need to consider time-related aspects of events and corrective actions....For the duration of each generating unit outage, there is an increase in the cost of providing electricity to the consumer. This is not true of transmission; transmission unreliability by itself rarely affects costs of electricity directly except for increased losses. However, there may be indirect effects due to generating units being required to operate in below-optimum combinations when transmission outages restrain their output" (Appendix R-1, p. 253).

The Regional Reliability Councils have set standards for transmission security which have been discussed above. Achieving those standards in a least-cost manner is by and large the responsibility of individual member utilities. Pages 259-267 of Appendix R-1 provide the individual Council responses to the Regional Reliability Council survey question concerning the role of economics in reliability considerations. Pages 353-377 of Appendix R-1 provide Council responses to the survey question regarding Council organizational agreement reference to economics.

The power pool responses differ from those of the other Councils in that pool operation is designed to provide a degree of reliability consistent with Council reliability criteria in a more economical manner than would be possible with the operation of isolated systems.

The ECAR Agreement addresses the issue of economics in Article 10, which states that..."Each ECA company will study the possibility of additional arrangements between its system and one or more systems of ECAR companies contiguous with its own that will contribute to achieving the objective of the parties to render reliable service and that will also contribute to operating economies to the fullest extent consistent with that objective. Such arrangements pertain, among other things, to such matters as ownership and operation of generation and transmission facilities, mutual assistance, and interchanges of electric capacity and energy for improvement of service and economy" (Appendix R-1, p. 353).

A Council's guidelines on the ability of a system to withstand extreme or more probable contingencies may reflect a balance of reliability and economic concerns. MAAC Criteria, for example, require that systems "be designed to withstand more likely events while the need to design the system to withstand less probable events depends on the severity of the consequences of the event and the costs of the necessary improvements to mitigate those consequences" (Appendix R-1, p. 259).

The disparity in prices of fuels for generation in the early and middle 1980s occasioned significant increases in economy energy transactions (Appendix R-1, p. 314). References to several studies addressing the capability of the bulk electric supply system to provide for such transfers, either currently or in the foreseeable future, or to examine the costs and benefits of modifying the bulk electric supply system to facilitate economy transactions were submitted in response to the Regional Reliability survey. These include: the 1985 Florida Oil Backout Study (Appendix R-1, p. 131); a MAIN study which includes the effect of off-peak (economy) transactions on the bulk electric supply system (Appendix R-1, p. 266); and the "ECAR/MAAC Interregional Power Transfer Analysis" (Appendix R-1, pp. 299-316).

RELIABILITY COUNCIL PERSPECTIVES ON OPEN TRANSMISSION ACCESS

Several references to the issue of open access to transmission facilities were included in responses to the Regional Reliability Council surveys.

NERC's "1986 Reliability Review" states that..."The costs of using existing transmission facilities should be proportionately shared by the utility owning the facilities and any third parties who wish to wheel power over them. The costs should include both the cost of replacement of the facilities and the value gained through the use of them. If third party access means that some reinforcement will be required earlier than would otherwise have been required (if at all), an equitable sharing of the costs of the addition should include the third parties. If it does not, the utility and its large pool of customers in effect subsidize the third parties" (Appendix R-1, p. 114). In its 1987 Reliability Review, NERC states that..."Technical aspects of...[open access] must be examined very closely since reliability may be adversely affected:...[M]ultiple uses of the transmission systems require a high level of continued coordination to assure that transmission facilities are not overloaded, that system stability is maintained, and that unforeseen line outages do not result in major service interruptions to customers. Open access to the transmission network could have a detrimental impact on bulk system reliability because of power flows on the transmission systems in directions and magnitudes never envisioned" (p. 42).

In its response to a question concerning important impediments to the pursuit of regional least-cost bulk power supply sales/purchases, MAPP responded: "As a voluntary pooling mechanism, MAPP members feel that proposals calling for mandatory access to members' transmission facilities are unsound, and would impinge on the network's safety, reliability and economic advantages." In regard to compensation for wheeling services, MAPP stated that "A fair method is needed to compensate systems for investment costs and increases in operating expense, other than losses, for use of their facilities to wheel power. MAPP has seriously studied this problem for some time and may develop such a method in the near future" (Appendix R-1, p. 348).

RELIABILITY COUNCIL PERSPECTIVES ON NON-UTILITY POWER

Responses to the survey of Regional Reliability Councils included several references to non-utility power and its potential impact upon the electric utility industry.

NERC's "1986 Reliability Review" notes that while non-utility generation accounted for 11% of the capacity additions in the United States, operators of most of these facilities do not have the same obligations as utilities to continuing operations and electric reliability. The predominant fuel for non-utility generation is natural gas, which is vulnerable to curtailments during cold weather when electric demands are high (Appendix R-1, p. 96).

NERC points out that cogeneration and small power production is anticipated to provide about 9,787 MW in the 1986-1995 period, based on a survey of U.S. utilities reporting capacity additions to U.S.D.O.E. under IE-411,but that this total may be underreported (Appendix R-1, p. 99).

NERC asserts that non-utility power production potentially has both positive and negative effects on power supply adequacy. Positive effects include: 1) shorter lead time for units; 2) non-utility financing, which eases utility capital requirements; and 3) more efficient use of energy sources through cogeneration. Potentially negative effects include: 1) cogenerators will operate more in response to industrial process than to utility system customer needs; 2) long-term operation is subject to profitability; 3) susceptibility to fuel availability and price changes; 4) non-responsiveness to daily cycles in electric loads, requiring utilities to follow load variations with low-cost units; 5) potential loss of utility transmission capacity and difficulty in transmission planning, depending on transmission access policies; and 6) impact of increased utility load-following on utility generation (raised costs, maintenance, and possible outage rates) (Appendix R-1, p. 103).

The "1986 Reliability Review" also notes that individual states have adopted differing standards on QF conditions and obligations. It states that utilities need flexibility to negotiate with QFs on energy, capacity and wheeling costs, on connection requirements, and on generation schedules (Appendix R-1, p. 104).

Appendix R-1, Exhibits 46 and 47 (p. 99a) present projections of non-utility generation additions by fuel type for the period 1986-1995, and the amount of non-utility generation included in NERC generating unit additions projections for 1986-1995 by region. Appendix R-1, Exhibit 48 presents the results of a 1986 NERC survey of cogeneration and small power production facilities anticipated by 1995, by region (p. 99b).

Additional comments from the "1986 Reliability Review include:

"Large cogenerators or a multitude of small power producers in the same area can cause reliability problems such as overloads, parallel path flow limitations, transmission system instability, voltage changes, etc. One detrimental effect on reliability of non-utility generation is also one of its advantages: the short time required for installation. Non-utility generation can be installed quickly -- before adequate transmission can be constructed; therefore, reliability may fall below acceptable levels" (Appendix R-1, p. 111).

"There is growing interest in achieving access to utility transmission systems by non-utility power producers. Some are seeking to wheel power to the utility having the highest avoided cost. Others, such as industrial cogenerators, wish to serve loads at locations remote from the generating site. Both wish to use the transmission systems of intervening utilities. To maintain reliability, a utility should have control of its system. If wheeling interferes with this control, the system operator's ability to respond in the event of an emergency will be compromised, and reliability may suffer" (Appendix R-1, p. 113).

NERC's "1987 Reliability Review" reveals that NERC utilities have reported to U.S.D.O.E. in their IE-411 reports that they expect about 11,700 MW of non-utility generation to be added over the 1987-1996 period (p. 20). Among the issues of concern regarding non-utility generation, NERC lists 1) reactive power support and voltage control; 2) supply planning uncertainty; 3) siting considerations; 4) transmission loading problems; 5) lead time for new facilities; 6) unit performance statistics; 7) capacity forecasting complications; 8) rapid operational mode changes; 9) backup capacity requirements; and 10) integration into utility operations (p. 29). NERC notes its recent issuance of "Reliability Considerations for Integrating Non-Utility Generating Facilities with the Bulk Electric Systems" in April 1987. "If the operator of the non-utility generator recognizes the issues and adheres to the recommendations in this document, NUG [non-utility generation] operation should be compatible with utility operations" (p.30).
ERCOT states that the role of cogeneration is one of the issues of most concern to its member systems which affects reliability. "Most cogenerators in Texas require baseload type operation because it is compatible with the associated industrial process and also most economical. Since this resource affects so many areas...it will have a profound impact on developments in ERCOT in future years. Central station capacity in the planning stage may be postponed as additional cogeneration ventures develop. Since cogeneration owners are basically interest in economic return, utilities who contract for such generation must assure a proper balance with reliability" (Appendix R-1, p. 121). The "1987 Reliability Review" states that up to 2,475 MW of non-utility generation capacity may be available in ERCOT by 1996 (p. 53).

MAAC notes the considerable potential for development of non-utility generation in its area, and cites its concern with the effect of such facilities on reliability of supply. This effect is..."a function of many factors, including their availability, willingness to coordinate maintenance schedules, effect of transmission systems, and effect on light load operation due to their non-dispatchability. If the facilities are installed when scheduled, remain in business and perform well as an integrated part of the supply system, reliability could be enhanced. Alternatively, reliability could be adversely affect if non-utility generation included in the forecasts is not developed, ceases operation prematurely or if the performance characteristics are substantially below those currently projected for the facilities. System reliability could also be adversely affected if the installation and operation of non-utility generation connected to a system that was not originally designed for additional generation are not coordinated with installation of required transmission system reinforcements, and operation of the integrated electric supply system (Appendix R-1, pp. 122-123). NERC's "1987 Reliability Review" states that about 3,300 MW of non-utility generation are anticipated by 1996 including 2,800 MW yet to be installed. "If less than about 2,000 MW of this non-utility generation materializes, generating capacity may be inadequate in the latter part of the forecast period" (p. 56).

NPCC states that there is some concern in both the New York and New England pools about the dependability of non-utility capacity. "Reliability could be adversely affected by the fact that most of it will not be dispatched by either the pool or member utility system operators. Further, low or unstable oil prices may result in cancellation of some planned installations by the independent producers themselves" (Appendix R-1, p. 129). SERC voices similar concerns (Appendix R-1, p. 133).

REGIONAL RELIABILITY COUNCIL PERSPECTIVES ON STATE REGULATION OF TRANSMISSION SITING AND OBSTACLES TO INTERCONNECTION

Several observations on the impact of state regulation on transmission siting and on regulatory obstacles to interconnection were provided in the responses to the Regional Reliability Council survey.

NERC's "1986 Reliability Review" cites four general impediments to the construction of new transmission: 1) the requirement to assure future benefits; 2) lengthy licensing procedures; 3) conflicting jurisdictions; and 4) lack of incentives for the utility (Appendix R-1, p. 108). Licensing and cost recovery difficulties are discussed on page 112 of Appendix R-1, where it is stated that "in the last few years, some major utility costs for generating plants and transmission lines in the United States have been disallowed after project completion." The impact of disallowance in the case of proposed revisions to the Financial Accounting Standards Board's 1982 statement of financial accounting standards is also discussed.

"Impediments to Transfers", a report prepared for the NARUC Committee on Electricity by NERC in 1984, presents a list of regulatory and legal impediments to the addition of transmission or maximization of transfers (Appendix R-1, pp. 273-274).

The "ECAR/MAAC Intraregional Power Analysis" document states that the financing of major new facilities is a major hurdle requiring assurances to the companies involved that the required return on investment can be achieved. Delays involving licensing and rights of way acquisition are also problematic, as are difficulties in demonstrating local benefits for transmission projects. Finally, regulatory treatment of investment and operational savings provides little incentive for involvement in regional transmission projects (Appendix R-1, p. 303). Additional remarks on "Demonstration of Need" and "Assessment of Environmental Impact" and of excessive time requirements associated with obtaining them, on delays associated with appeals and obtaining land rights are provided on pages 310-311 of Appendix R-1.

Proposed improvements to the regulatory process are also presented in the report "ECAR/MAAC Interregional Power Analysis" on page 312 of Appendix R-1.

DRAFT

ELECTRIC UTILITY GENERATION AND TRANSMISSION PLANNING AND COORDINATION:

SUMMARY OF UTILITY RESPONSES TO A SURVEY BY THE NATIONAL GOVERNORS' ASSOCIATION TASK FORCE ON ELECTRICITY TRANSMISSION

APPENDIX 1 -- ADDITIONAL COMMENTS BY RESPONDENTS

JULY 1988

Note: This document was prepared by staff members of the Public Utilities Commission of the State of Ohio under contract with the U.S. Congress, Office of Technology Assessment, Washington, D.C. This document was prepared for reference purposes and is being distributed for review and comment only and should not otherwise be reproduced, referenced or quoted. The conclusions expressed in this paper are those of the authors and do not necessarily reflect the views of the Office of Technology Assessment, the Public Utilities Commission of Ohio, or the National Governors' Association Task Force on Electricity Transmission. This document has not been reviewed or approved by the Technology Assessment Board.

GENERATION AND TRANSMISSION CHARACTERISTICS

In addition to information on the characteristics of major transmission lines under construction, question 4 asked also for the purpose of the lines. The purposes were reviewed by NERC geographic regions, which include pool and non-pool companies, to determine any patterns evident.

ECAR: In the ECAR region four power pools are in existence (Allegheny Power System, American Electric Power System, Central Area Power Coordination Group and Michigan Electric Coordination System). For the power pools the purpose to construct is system upgrade and reliability, whereas for the non-pool efforts increase in distribution (e.g. substations is the construction purpose). Overall service security appears to be the underlying trend.

ERCOT: There are two power pools in the ERCOT region (Texas Municipal Power, Texas Utilities Company). For the power pools the purpose to construct is system extension. Non-pool construction is aimed at reliability and capability. Service extension and the increased need for system reliability appear to be the trend.

MAAC: The trend for the pool companies is to increase reliability and capacity which is reflected in the construction projects of the non-pool company.

MAIN: The survey respondents for this region were all non-pool companies. Therefore, no definite statement can be made about the region. For the non-pool companies delivery capabilities were the trend.

MAPP: MAPP is a power pool and a region with several non-pool companies providing service in the region. The majority of the respondents were power pool companies. System reliability and capacity upgrades were the trend in the construction projects.

NPCC: All respondents are pool members. The construction trends for the region are, therefore, not completely documented. For the pool companies system reinforcement is the trend.

SERC: The pool companies showed a trend governed by load and reliability reasons. This was the same for the non-pool companies.

SPP: There are two power pools in the SPP region (Middle South Utilities and Missouri-Kansas). For the pool companies as for the non-pool companies the trend clearly is reliability and capacity.

WSCC: There are two power pools in the WSCC region (California Power Pool and Pacific Northwest Coordination Agreement). As in the SPP region the trend is the same for both pool and non-pool companies. Capacity growth is the region wide trend for the construction projects.

In general it can be said that the regional trends follow two reasons; a) demographic shifts connected with industrial development, and b) age mix of generating units within a given region. And further more economy or the provision of economy energy service was not stated by any company explicitly in any of the surveys.

TRENDS IN BULK POWER PURCHASES AND SALES

Question 8 asked for a description of any additional transmission capacity needed to undertake the contracts discussed in Question 7. In addition a description of the status of the transmission siting application was asked for.

The responses were sorted and categorized by council and within by IOU, MUNI, REC and FSD.

ECAR - IOU: Only one company in the council had a project which was the installation of a new transformer of a 500 KV interconnection.

MUNI: One company has a project involving a new substation and a 138 KV line. Right-of-way acquisition is in progress and no siting is needed.

REC, FSD: none

ERCOT - IOU: One of two respondents has a 138 KV project.

MUNI, REC, FSD: none

MAAC - IOU, MUNI, REC, FSD: none

MAIN - IOU, MUNI, REC, FSD: none

MAPP - IOU: No additional capacity is needed.

MUNI, REC, FSD: none

NPCC - IOU, MUNI, REC, FSD: none

SERC - IOU: The vast majority of the respondents did not need any additional capacity. Of the four companies responding positively three states said that they needed system improvements which were achieved by advancing planned facilities if practicable. One company constructed a 230 KV line but nothing was said about siting.

MUNI: none

REC: One company needed a 230 KV line to interconnect with a state grid. No siting was mentioned.

FSD: No additional capacity required.

SPP - IOU: The vast majority of the respondents did not need any additional capacity. Construction was required by three companies with projects ranging from 230 KV to 345 KV. These projects were mainly interconnections. No power siting application was needed.

MUNI, REC, FSD: none

WSCC - IOU: The vast majority of the respondents did not need any additional capacity. One company had several small projects with no siting permits needed.

MUNI, REC, FSD: none

PLANNING AND FORECASTING

Questions 20 (in part) and 23 (in part) asked for qualitative information about utility planning and forecasting.

Question 20.

Question 20 asked, in part, for a brief description of how transmission and/or generation planning is coordinated on a regular basis. The responses seemed to fall into four broad categories (in decreasing order of mention): "through meetings with neighboring utilities", "through a N.E.R.C. reliability council committee", "through a power pool", and "through other utility trade organizations". When the responses were reviewed by utility type, it was found that IOU respondents mentioned "neighbors" most frequently, Municipal respondents mentioned "trade organizations" most frequently, and REC respondents mentioned "neighbors" and "N.E.R.C. committees" most frequently.

The responses were reviewed by N.E.R.C. region, but no pattern was discernible.

Question 23.

Question 23 asked for an assessment of seven potential rationales for building transmission lines:

a. to provide inter-state transmission service for others;
b. to provide intra-state transmission service for others;
c. enhanced service area reliability;
d. to purchase power for your own use from other utilities;
e. increased opportunities to sell your existing generation to other utilities;
f. to purchase power from one neighboring utility to sell to another;
g. increased opportunities to sell power from your planned generating facilities to other utilities.

The respondent was asked to choose one of: "yes, possibly, unlikely, no". If the response for a rationale was "unlikely" or "no", the respondent was requested in part 2 to describe any regulatory changes which would induce a reconsideration.

This question was analyzed by sorting the responses into two categories "yes/possibly" and "no/unlikely". The "yes/possibly" responses are listed below. The "no/unlikely" responses were further sorted into categories by consolidating similar responses to part 2 of the question and the choices to part 1 are listed.

Seventy respondents answered all "yes and possibly" without any additional narrative response.

Six answered all "yes and possibly" and responded that it depends on the economics of the particular situation and the benefits to its customers and ratepayers.

One responded that all service would be considered to be interstate commerce and solely within the jurisdiction of FERC.

One responded that the decision to build a transmission line requires a case by case evaluation.

One answered all "yes and possibly" and responded if FERC were to confer a value-based rate on the wheeler to cover the value of the service rendered, then these might be worthy items. If siting decisions were not so complex, then the services might be pursued.

One responded that our system is such that these situations are not likely to occur. Three did not respond to this question, and one answered "not applicable".

The following are the results of categorizing the "no/unlikely" responses and listing the choices to part 1 of question 23:

RESPONSE	A	B	C	D	E	F	G
Unsure of what regulatory changes would be required.	2	1	0	2	2	2	2
Changes in siting regulations would not induce reconsideration.	7	6	1	0	5	7	6
Planning not to construct any new generation facilities within the current planning horizon.	10	6	0	1	1	3	4
Regulatory changes required would be to allow utility to recover investment from ratepayers and at a premium rate of return.	18	18	0	0	1	8	4
Cannot invest in any capital project that are not directly for the benefit of customers.	15	28	0	0	9	29	14
Placement of siting and certification under jurisdiction of state commission.	2	1	0	0	0	2	0
Transmission planning not limited by regulatory concerns.	2	2	0	1	0	2	0
Construction of such facilities would jeopardize tax exempt financing status.	1	1	0	0	0	0	0
State law requires that the utility demonstrate "need" to obtain approval of transmission facilities. Without approval, there is no method for recovery of equity or a return of such equity.	2	2	0	0	1	2	1

RESPONSE	A	B	C	D	E	F	G
A transmission line would not be "used and useful" and the company could not earn a return on the investment in the line.	1	1	0	0	0	1	0
Municipal organization should not be prohibited from "brokering power". We should be afforded the same opportunity as investor-owned utilities in being able to enhance revenue from transmission wheeling contracts or wheeling paths.	1	0	0	0	0	1	0
Would construct on a long-term lease for entire facility arranged prior to construction.	1	1	0	0	0	1	0

One did not respond to part 1 of question 24 but responded to part 2, that rules must be established that allow wheeling utilities to collect enough revenue to pay for the cost of the additions plus interest.

In addition, a large Midwestern utility responded to only part 2 of question 24: "construction of new transmission facilities for providing transmission service to others cannot be contemplated without major changes in the current siting and rate regulation or without special provisions with regard to siting and rate treatment."

Fifty-nine answered no/unlikely without any additional narrative response to part 2 of this question.

STATE REGULATION OF TRANSMISSION LINE PLANNING AND SITING

Questions 17 (in part), 18, 22, and 24 (in part) asked for information on utility perceptions of state regulation of transmission line planning and siting.

Question 17.

Question 17 asked whether the state in which the respondent has, or plans to have, transmission facilities has a process to regulate the siting of transmission facilities. Those who answered "yes" were further requested to: (A) describe those aspects of the process that facilitate or impede transmission siting and planning activities and (B) indicate in what ways the siting and certification process may be expedited.

Not many respondents gave aspects of the process that facilitate transmission siting and planning activities. The facilitating aspects that were mentioned seemed to fall into one of three categories: "standardized application format", "one stop review", and "allows public to be heard". "Standardized application format" was mentioned by respondents in Maryland, Virginia, and West Virginia. "One stop review" was mentioned by respondents in Connecticut, Florida, and New Hampshire. "Allows public to be heard" was mentioned by respondents in Kentucky, Michigan, Nebraska, New York, South Dakota, and Wisconsin.

When the surveys were reviewed for those aspects of the process that impede transmission siting and planning activities, "adds too much time" was by far the leading category, being mentioned by respondents in:

- Arizona
- California
- Illinois
- Iowa
- Massachusetts
- Minnesota
- Mississippi
- North Dakota
- Pennsylvania
- Texas

Respondents in California, Maine, and Massachusetts indicated an impediment was the multiplicity of regulatory bodies. Increased costs was mentioned by respondents in California, Idaho, and Pennsylvania.

When the surveys were reviewed for suggested ways in which the process may be expedited, "one stop siting" and "set specific time limits for decisions" were by far the categories most often mentioned. "One stop siting" was mentioned by respondents in ten states:

- Arizona
- California
- Illinois
- Iowa
- Maine
- Massachusetts
- Minnesota
- New Jersey
- South Dakota
- West Virginia

"Set specific time limits for decisions" was mentioned by respondents in twelve states:

- Colorado
- Kansas
- Maryland
- Massachusetts
- Minnesota
- Missouri
- New York
- Ohio
- Pennsylvania
- Texas West
- Virginia
- Wisconsin

Respondents in Massachusetts, Minnesota, and West Virginia linked these two categories by indicating that "one stop siting" would expedite the process if combined with specific time limits. Respondents in Califoria, Idaho, Washington, and Wyoming did not mention time limits but did suggest determining need at the earliest possible time in the siting process. A respondent in Montana indicated there were time limits, but suggested they should be reduced.

Respondents in Arkansas, Colorado, New Mexico, North Dakota and Ohio indicated the process needed to be reduced and streamlined, while respondents in Minnesota, Montana, New Mexico, Pennsylvania, and Texas indicated the need for better defined or clarified regulations, standards and procedures. A respondent in Maryland indicated that pre-emption of Commission approved projects from local planning and zoning would expedite the process.

Respondents in Nevada and North Dakota suggested the process could be expedited by working closely with the regulatory agency. Other respondents indicated that changes in the regulatory agencies would help expedite the process. Items mentioned were: increasing the size of the regulatory staff, speedier regulatory response, better coordination among state departments, and better compliance of regulators with their own rules.

Finally, respondents in Indiana, Kansas, Kentucky, Nebraska, New Hampshire, Oregon, South Carolina, and Wyoming believe the process either is reasonably expeditious in these states, or is at least not an impediment.

Question 18.

Question 18 asked, in part, whether there are now any problems with state-state or state-federal coordination of regulation of transmission facilities. Few respondents answered this part of the question. For most of those who did respond, the problem is a lack of state-federal coordination. Explanations were provided by respondents in:

- California
- Indiana
- Michigan
- Montana
- New Jersey
- New York
- Washington

These respondents explained that policies and procedures have not been established for joint state-federal siting, that many times concerns of state and federal agencies conflict, and that state and federal agencies do not seem willing to cooperate with each other. The jurisdiction of state and federal governments applies only to the sections of a project which cross the government land. One respondent indicated that a federal siting decision could result in a prohibition of a line to cross federal land even if the alternative results in greater adverse impact.

They further explained that state and federal agencies want information presented differently, and federal agencies often do not follow judgments made by states. The result is overlapping licensing efforts which can result in delays and unnecessary expense.

With respect to state-state coordination, a respondent from Wisconsin reported no problem to date, while a respondent from Pennsylvania reported a problem with different criteria by states requiring two separate and wholly different applications.

Question 22.

Question 22 requested specific examples of the lead times associated with the construction of new transmission facilities. In addition the question asked for the portion attributable to regulatory requirements and asked to what extent "regulatory" lead time varied from project to project.

The question asked for examples with no further specification. It is clear from the responses that this lack of specification resulted in no uniformity to the type of examples provided: some are "typical" examples, some are "most recent", and some are "horror stories". In addition some respondents provided a range of years, rather than specific examples; for purposes of this discussion they will be treated as examples.

IOU respondents had a range of example lead times from 8 months to 16 years, with half between 2 and 4 years. The range of regulatory lead times was from "none" to 16 years, with half being one year or less. On the other hand, 20% were 5 years or longer.

Two respondents indicated they were not subject to regulatory requirements; several others indicated that regulatory requirements could always be integrated into a normal planning schedule. One respondent indicated there was no delay because they found it necessary to risk proceeding in parallel with the regulatory process; however, another respondent indicated there was regulatory delay because prudent expenditure of funds required prior siting approval.

The most often mentioned lead time delaying factor was right-of-way acquisition, especially if eminent domain had to be invoked. Appeals and court challenges were also mentioned as delaying factors.

Most respondents indicated that regulatory lead time did vary among projects. Some respondents indicated that regulatory lead time varied proportionately with the length and voltage of the line (but one respondent stated that the regulatory process was lengthy regardless of how small the project). Others mentioned public intervention, type of structure, urban versus rural route, number of regulatory agencies involved, work load of the regulatory agencies, and whether federal land is involved.

Municipal respondents had a range of example lead times from 3 months to 7 years, with half being equal to or less than 2 years. The range of regulatory lead times was from "none" to 4.5 years, with 90% showing the maximum to be 2 years or less.

The most frequent comment by municipal respondents was that they were not affected by regulatory requirements. One respondent indicated there was no regulatory problem except that regulatory requirements of partners substantially increased lead time for joint projects.

Right-of-way acquisition was mentioned as a delaying factor and so was the appeals process. Other factors were environmental sensitivity of the land and the mind-set of decision making bodies.

REC/Other respondents had a range of example lead times from 3 months to 9 years, with half being equal to or less than 2 years. The range of regulatory lead times was from "none" to 5.5 years, with 90% showing the maximum to be 2 years or less.

The comments were similar to above, with one respondent adding that Indian land right-of-way is generally not available at reasonable time or cost and another respondent indicating that Rural Electrification Administration requirements caused delays.

Figures Q-3, Q-4, and Q-5 are scatter-diagrams showing the relationship of regulatory requirements to total lead time for IOU, Municipal, and REC/Other respondents, respectively.

Question 24.

Question 24 asks: "within the regulatory framework you currently face, are there circumstances in which you could obtain a certificate for a transmission line crossing your service area which serves the national interest, but does not substantially serve your ratepayers?" In addition, the question asks that if you responded yes, to briefly describe the circumstances and if you responded no, describe any regulatory changes which would make it possible.

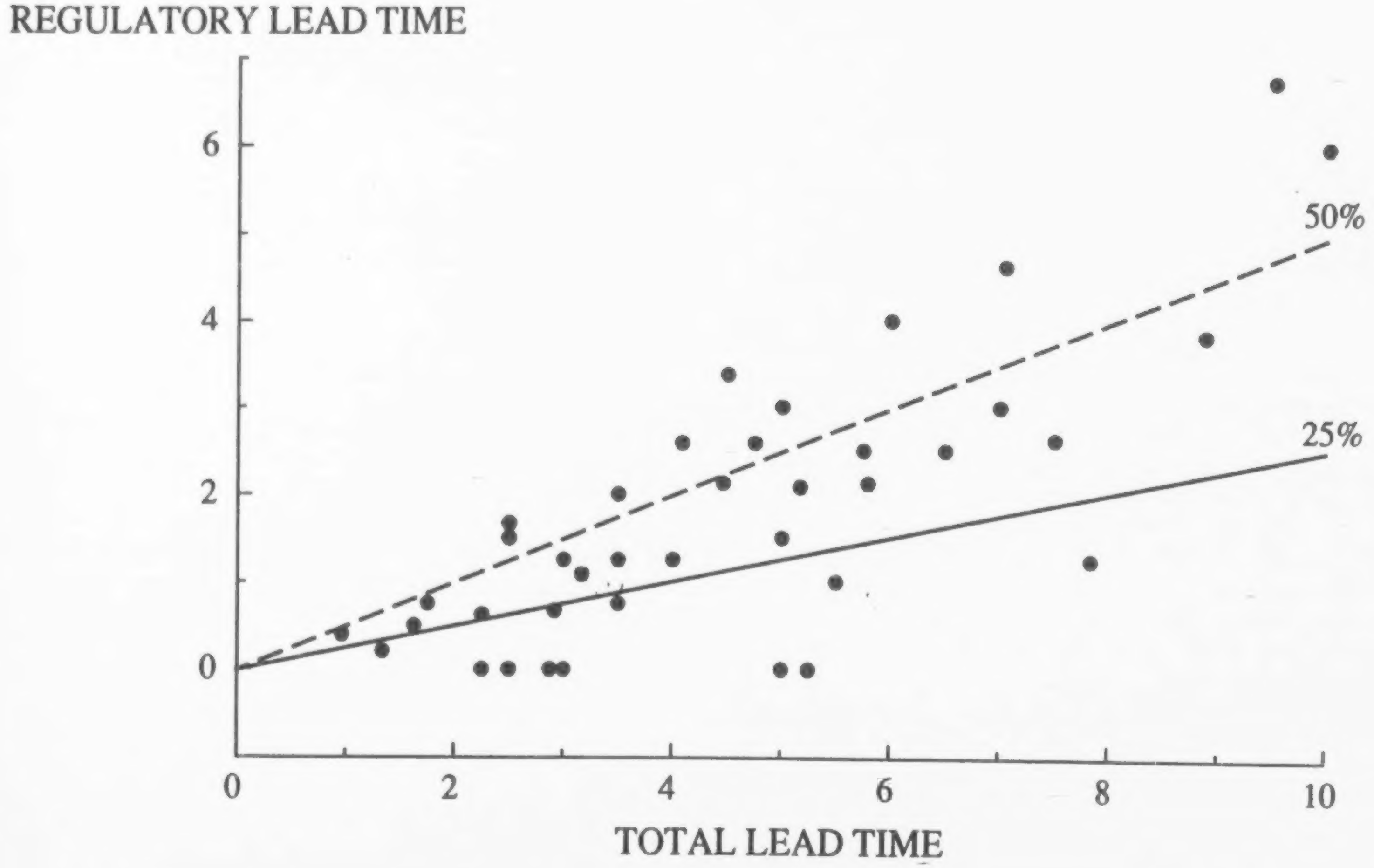
This question was analyzed by sorting the responses into categories of "yes" and "no" and consolidating the responses. A few of the responses were not relevant and were, therefore, not recorded. Some responses had more than one applicable answer and were counted accordingly. The total number of responses was 238.

One hundred and four respondents answered "no" and provided a variety of narrative responses. Seventeen of these who answered "no" indicated that the state law be changed and that the current law requires a finding of "necessity" for the transmission line.

Twelve utilities responded that the Federal Power Act be amended to provide certification authority to the FERC on matters of national interest involving interstate activity.

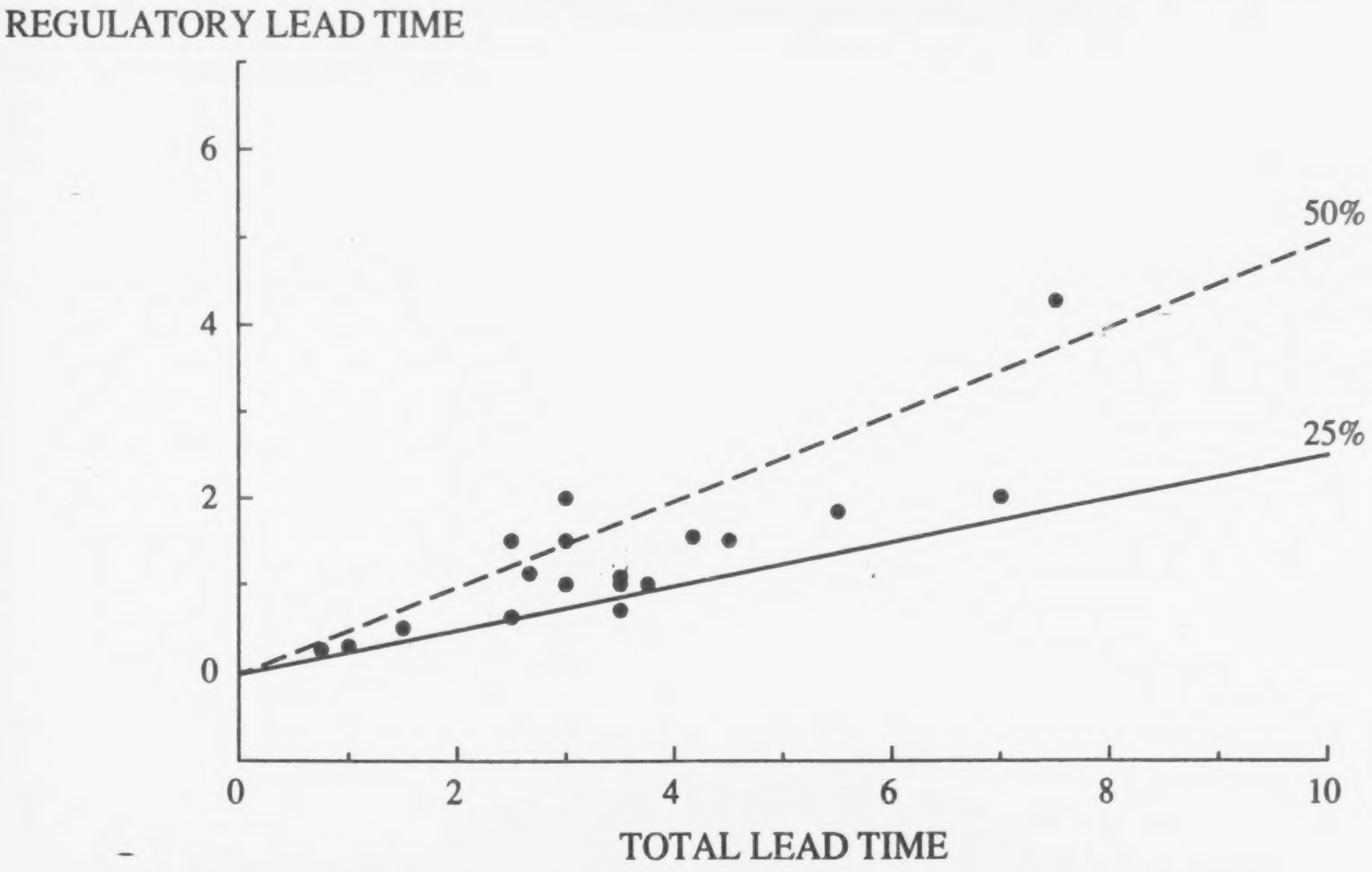
Four others responded that it would not be consistent with REA requirements and two more responded that it would be geographically unlikely.

FIGURE Q-3
IOU Respondents



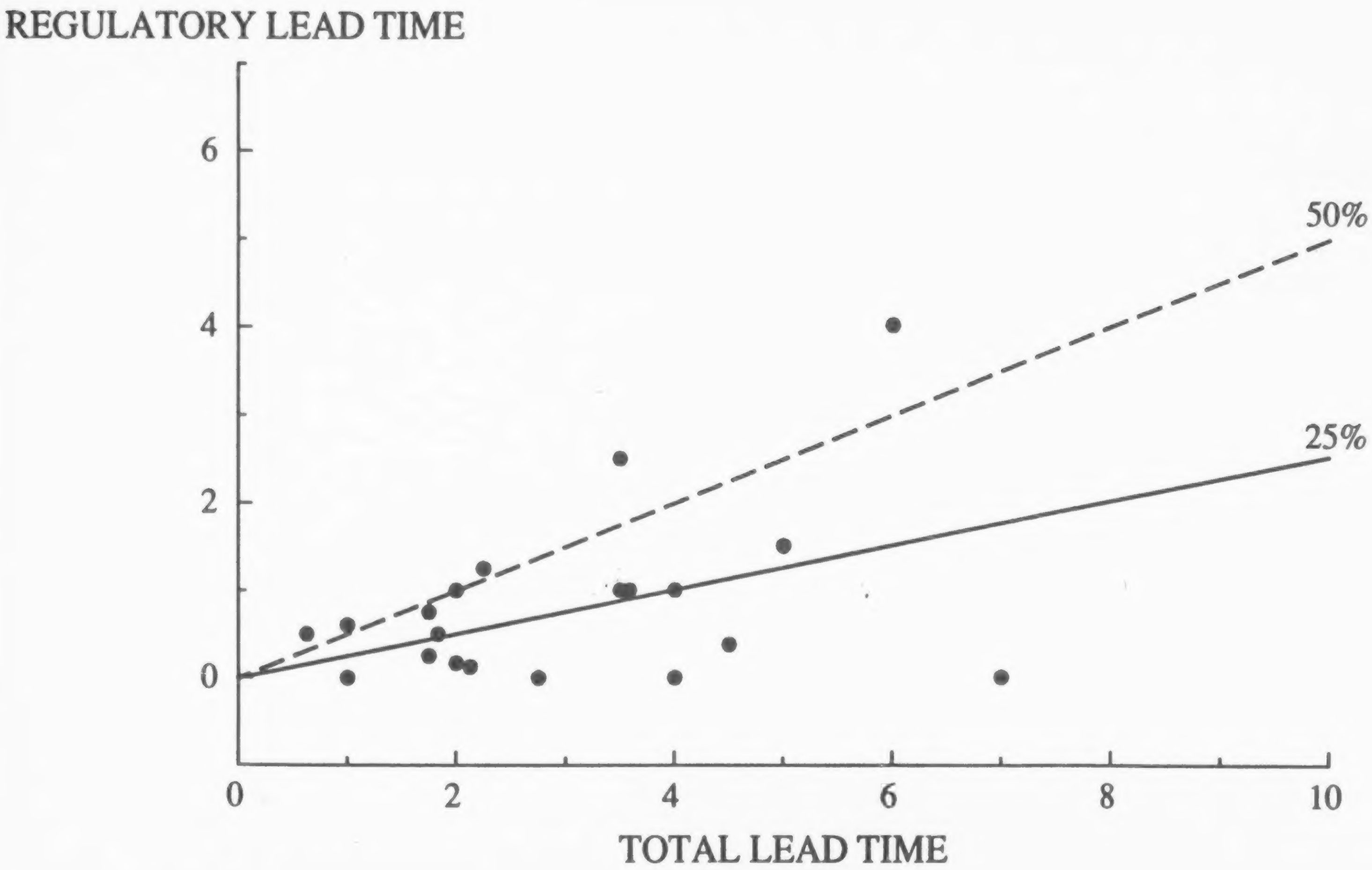
Notes: Points below the dotted line have regulatory lead time less than 50% of total lead time; points below the solid line have regulatory lead time less than 25% of total lead time.

FIGURE Q-4
REC & Other Respondents



Notes: Points below the dotted line have regulatory lead time less than 50% of total lead time; points below the solid line have regulatory lead time less than 25% of total lead time.

FIGURE Q-5
Municipal Respondents



Notes: Points below the dotted line have regulatory lead time less than 50% of total lead time; points below the solid line have regulatory lead time less than 25% of total lead time.

Five companies responded that it be required that transmission facilities planned would be for the benefit of the ratepayers.

Six companies responded that the "used and useful" test to determine whether or not company facilities may be included in rate base may need to be reconsidered.

A large Midwestern utility responded, "legislators and regulators would need to adopt a less parochial view of their role and perhaps regulation over such facilities should be assumed by a regional or federal authority."

Seventeen remaining responses that answered "no" to question 24 varied from "no experience in this type of certification and, therefore, no opinion can be rendered" to "cannot foresee a need to obtain a certificate for a transmission line that would have no benefit."

Forty-one respondents answered "no" without any additional narrative response to what regulatory changes would make it possible.

Forty-eight respondents answered "yes" to question 24 and, again, the responses were widely varied. Twenty-seven of those respondents that answered "yes" said that they would build a transmission line only if the ratepayers did not pay for it and only if the national interest outweighed the esthetic intrusion and if the transmission line is in the public interest.

A variety of remaining responses that answered "yes" are listed below:

Two companies said, "they currently have remote generation in neighboring states or Canadian provinces."

One company responded, "provided someone else paid for the line."

Five companies responded, "only for national defense; military emergencies; and air base installations."

Two companies responded that there are existing transmission lines crossing their service area and are owned by others.

One company said, "that regulations do not prevent such a project and much depends on the pressure brought to bear on the agency."

Five companies answered "yes" and responded that they would build a transmission line if they got permission from their state Commission.

A total of 35 respondents answered "unknown" and/or "uncertain" with a variety of responses. For example, one company replied that they are not familiar with the rules and that such a situation has not arisen.

A large West Coast utility responded, "with service areas in diverse locations, it is necessary to cross service areas that are not directly served by the transmission line. Reinforcement of the transmission grid requires lines that do not serve load in the areas they traverse."

The remaining 18 responses that answered "unknown" and/or "uncertain" said that they would have to have approval from their state Commission and the transmission line would have to be "used and useful".

Fourteen respondents answered "unknown" and/or "uncertain" without any additional response. Thirty one respondents answered "not applicable" and offered no additional response.

Question 24 was also sorted by state to assess whether there were any identifiable trends or patterns in the responses. The following are the only patterns discovered:

Arizona - Three answered "no" and responded that they are required to demonstrate that the transmission facilities are a benefit to the rate payers.

Hawaii - Three answered "no" and responded that this situation is unlikely to occur because of isolation from other state rather than regulatory guidelines.

Oregon - Three out of four companies answered "unknown" or "uncertain"; the fourth company from Oregon answered "yes" and responded, "provided the facilities met all state and federal regulatory requirement."

DRAFT

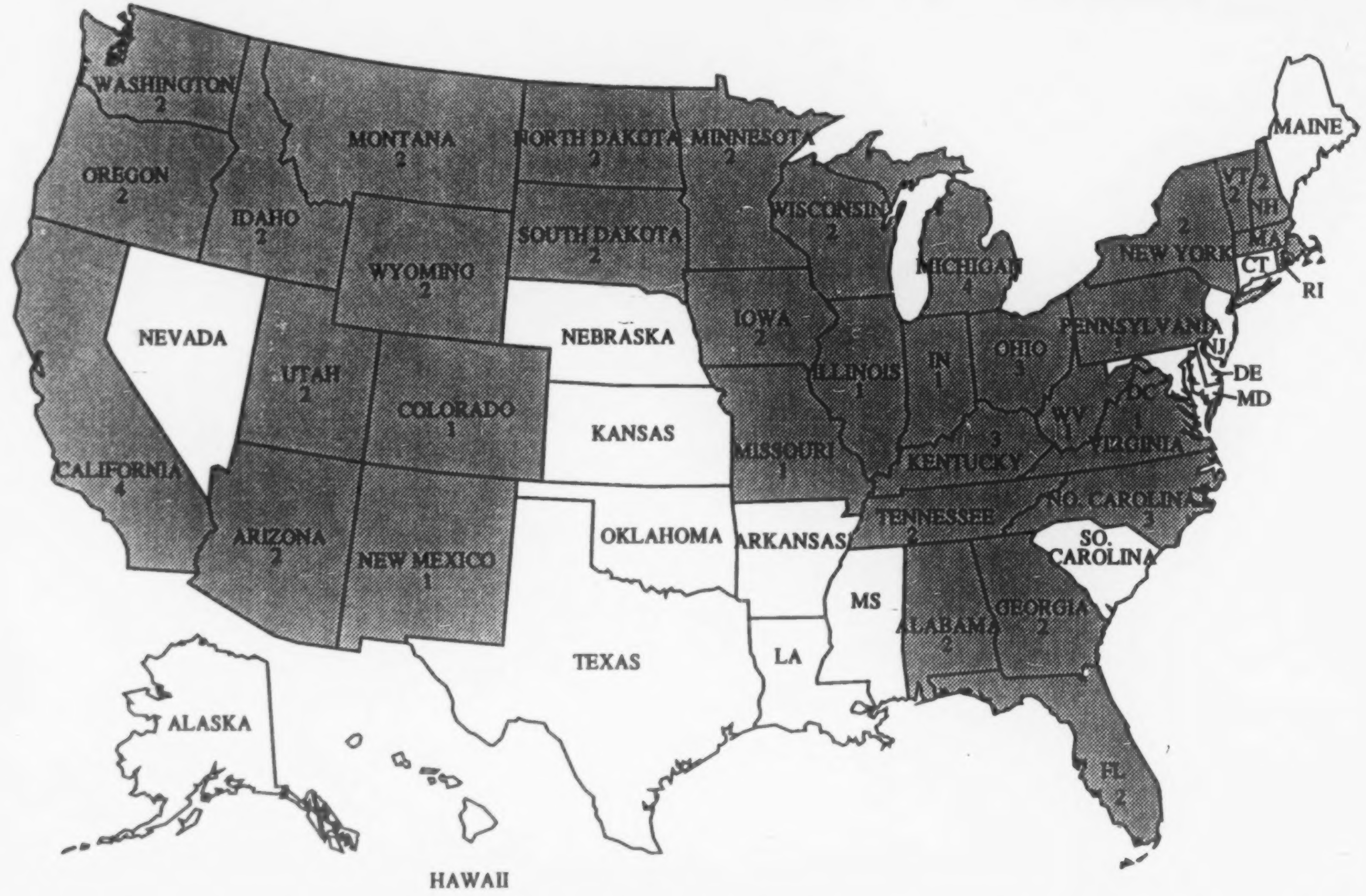
PLANNING AND COORDINATION OF UTILITY BULK POWER SUPPLIES AND TRANSMISSION CAPACITY:

PRELIMINARY ANALYSIS OF INTERVIEW DATA FROM THE NATIONAL GOVERNORS' ASSOCIATION TASK FORCE ON ELECTRICITY TRANSMISSION

JULY 1988

Note: This document was prepared by staff members of the Public Utilities Commission of the State of Ohio under contract with the U.S. Congress, Office of Technology Assessment, Washington, D.C. This document was prepared for reference purposes and is being distributed for review and comment only and should not otherwise be reproduced, referenced or quoted. The conclusions expressed in this paper are those of the authors and do not necessarily reflect the views of the Office of Technology Assessment, the Public Utilities Commission of Ohio, or the National Governors' Association Task Force on Electricity Transmission. This document has not been reviewed or approved by the Technology Assessment Board.

Geographic Distribution of Interview Respondents


WASHINGTON 2
OREGON 2
CALIFORNIA 4
IDAHO 2
NEVADA
MONTANA 2
WYOMING 2
UTAH 2
ARIZONA 2
COLORADO 1
NEW MEXICO 1
NORTH DAKOTA 2
SOUTH DAKOTA 2
NEBRASKA
KANSAS
OKLAHOMA
TEXAS
MINNESOTA 2
IOWA 2
MISSOURI 1
ARKANSAS
LA
WISCONSIN 2
ILLINOIS 1
MS
MICHIGAN 4
IN 1
OHIO 3
KENTUCKY 3
TENNESSEE 2
ALABAMA 2
GEORGIA 2
FL 2
WV 1
VIRGINIA
DC 1
NO. CAROLINA 3
SO. CAROLINA
PENNSYLVANIA 1
NEW YORK 2
VT 2
NH 2
MA
CT
RI
NJ
DE
MD
MAINE
ALASKA
HAWAII

Note: Shaded area identifies states in which interview respondents operate.
Numbers represent respondents operating in the state.

TABLE I-1: PROFILE OF INTERVIEW RESPONDENTS

Name of Organization	Responded to Questionnaire	Type of Organization	State	Reliability Council Region	Generating Megawatt Capability	Megawatt Summer Peak	Megawatt Winter Peak	Utility Crosses State Boundaries	Member of Major Power Pool	Miles of Trans. 69KV & Above
Alabama Electric Coop.	NO	COOP	AL	SERC	584	545	521	NO	INA	46-345 KV 1696 Circuit Miles
American Electric Power	YES	IOU	IN, KY, MI, OH, TN, VA, WV	ECAR	23806	17342	20263	YES	YES	19215
American Municipal Power-Ohio	NO	District System Municipal	OH	ECAR	0	445	407	NO	NO	0
Arizona Public Service Company	YES	IOU	AZ	WSCC	3265	3198	2358	NO	NO	4675
Associated Electric Coop. Inc.	YES	COOP	MO	SPP	2442	1487	1653	NO	NO	2066
Bonneville Power Authority	NO	Federal System	OR, WA, ID, MT	WSCC	12445	15009	18516	YES	NO	115-500 KV 800 VDC 14021
Commonwealth Edison Company	YES	IOU	IL	MAIN	22037	13055	11713	NO	NO	3612
Deseret Generation and Trans. Coop.	YES	COOP	UT	WSCC	457	INA	INA	NO	NO	276
Detroit Edison	NO	IOU	MI	ECAR	10588	7172	6270	NO	YES	120-345 KV 2612 Circuit Miles
Duke Power Company	YES	IOU	NC	SERC	15020	11204	12687	NO	NO	5188
Florida Electric Power Coor. Group	NO	Power Pool	FL	SERC	NA	NA	NA	NA	NA	NA
Florida Power & Light Company	YES	IOU	FL	SERC	12582	10654	12533	NO	NO	5165

TABLE I-1 (Cont.)

Name of Organization	Responded to Questionnaire	Type of Organization	State	Reliability Council Region	Generating Megawatt Capability	Megawatt Summer Peak	Megawatt Winter Peak	Utility Crosses State Boundaries	Member of Major Power Pool	Miles of Trans. 69KV & Above
Georgia Power Co./Southern Co.	YES	IOU	GA	SERC	11874	11079	10049	NO	YES	11241
Iowa Public Service Company	YES	IOU	IA	MAPP	1299	692	618	NO	YES	1593
Kentucky Utilities Company	YES	IOU	KY	ECAR	3192	2277	2453	NO	NO	3957
Los Angeles Dept. of Water & Power	YES	MUNI	CA	WSCC	4252	INA	INA	NO	NO	2135
Missouri Basin Municipal Power Agency	NO	District System Municipal	IA, MN, ND, SD	MAPP	332	88	132	YES	YES	0
New England Electric System/NEPOOL	YES	IOU Power Pool	MA, NH, RI, VT	NPCC	3840	3555	3437	YES	YES	2102
Power Authority of the State of New York (Two Interviews)	NO	State System	NY	NPCC	6889	Annual Peak 23000		NO	YES	46-765 KV 1638 Circuit Miles
Niagara Mohawk Power	NO	IOU	NY	NPCC	5817	5308	5862	NO	YES	12-345 KV 9080 Circuit Miles
North American Electric Reliability Council	NO	Reliability Council	NA	NA	NA	NA	NA	NA	NA	NA
North Carolina Electric Membership	YES	COOP	NC	SERC	0	1227	1545	NO	NO	805
Northern States Power-Minnesota, Wisconsin (Two Interviews)	YES	IOU	MN, SD, ND MI, WI	MAPP	789	675	733	YES	YES	6030
Ohio Edison Company	YES	IOU	OH, PA	ECAR	5476	4069	4101	YES	NO	5071
Pacific Gas & Electric Company	YES	IOU	CA	WSCC	14068	14403	11625	NO	NO	13614

TABLE I-1 (Cont.)

Name of Organization	Responded to Questionnaire	Type of Organization	State	Reliability Council Region	Generating Megawatt Capability	Megawatt Summer Peak	Megawatt Winter Peak	Utility Crosses State Boundaries	Member of Major Power Pool	Miles of Trans. 69KV & Above
Pacific Power & Light Company	YES	IOU	CA, ID, MT, OR, WA, WY	WSCC	4066	3222	4253	YES	YES	7298
Public Service Company of New Hampshire	YES	IOU	NH	NPCC	1635	1144	1375	NO	YES	987
Public Service of Colorado	YES	IOU	CO, WY	WSCC	3019	3137	3153	YES	NO	4418
Public Service of New Mexico	YES	IOU	NM	WSCC	1307	861	814	YES	NO	1803
Salt River Project	YES	State System	AZ	WSCC	3453	2478	2143	NO	NO	1470
San Diego Gas & Electric Company	YES	IOU	CA	WSCC	3042	2342	1781	NO	YES	1646
Tennesse Valley Authority	NO	Federal System	AL, GA, KY, NC, TN	SERC	32089	18423	22237	YES	NO	46-500 KV 17225 Circuit Miles
Utah Associated Municipal Power System	YES	District System Municipal	UT	WSCC	57	Annual Peak 250		NO	NO	50
Vermont Electric Power	NO	IOU Trans. Co.	VT	NPCC	NA	NA	NA	NO	YES	INA
Western Area Power Administration	NO	Federal System	15 Western States	WSCC MAPP	NA	NA	NA	YES	NO	34.5-500 KV 16119 Circuit Miles
Wisconsin Public Power Inc. (Two Interviews)	NO	District System Municipal	WI	MAPP MAIN	NA	NA	310	NO	INA	NA

NOTES:
NA - Not Applicable
INA - Information Not Available

Summary Tabulation of Interviewees Responses to Question 15 and 16 of the Utility Questionnaire

State	Type of Organization	Reliability Council Region	15A	15B	15C	15D	16A	16B	16C	16D	16E	16F	16G	16H
Arizona	FED SYS	WSCC	NO	NO	NO	NO	NO	NO	NO	YES	NO	NO	NO	NO
Arizona	IOU	WSCC	NO	NO	NO	NO	NO	NO	NO	YES	NO	NO	NO	NO
California	IOU	WSCC	NO	NO	NO	NO	NO	YES	NO	NO	NO	NO	NO	NO
California	IOU	WSCC	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO
California	IOU	WSCC	NO	NO	NO	NO	NO	NO	YES	NO	NO	NO	NO	NO
California	MUNI	WSCC	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO
Colorado	IOU	WSCC	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO
Florida	IOU	SERC	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO
Georgia	IOU	SERC	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	YES
Idaho	IOU	WSCC	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO
Illinois	IOU	MAIN	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	YES
Indiana	IOU	ECAR	NO	YES	YES	NO	NO	NO	NO	NO	NO	NO	NO	YES
Iowa	IOU	MAPP	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO
Kentucky	IOU	ECAR	NO	YES	YES	NO	NO	NO	NO	NO	NO	NO	NO	YES
Kentucky	IOU	ECAR	NO	NO	NO	NO	NO	YES	NO	NO	NO	NO	NO	NO
Massachusetts	IOU, PP	NPCC	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO
Michigan	IOU	ECAR	NO	YES	YES	NO	NO	NO	NO	NO	NO	NO	NO	YES
Michigan	IOU	MAPP	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	YES
Minnesota	IOU	MAPP	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	YES

Cont...

State	Type of Organization	Reliability Council Region	15A	15B	15C	15D	16A	16B	16C	16D	16E	16F	16G	16H
Missouri	COOP	SPP	NO	NO	NO	YES	NO	NO	NO	YES	NO	NO	NO	NO
Montana	IOU	WSCC	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO
New Hampshire	IOU	NPCC	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO
New Hampshire	IOU, PP	NPCC	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO
New Mexico	IOU	WSCC	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO
North Carolina	COOP	SERC	NO	NO	NO	NO	YES	YES	NO	NO	YES	YES	YES	NO
North Carolina	IOU	SERC	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO
North Dakota	IOU	MAPP	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	YES
Ohio	IOU	ECAR	NO	YES	YES	NO	NO	NO	NO	NO	NO	NO	NO	YES
Ohio	IOU	ECAR	NO	NO	NO	NO	NO	YES	NO	NO	NO	NO	NO	YES
Oregon	IOU	WSCC	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO
Pennsylvania	IOU	ECAR	NO	NO	NO	NO	NO	YES	NO	NO	NO	NO	NO	YES
Rhode Island	IOU, PP	NPCC	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO
South Dakota	IOU	MAPP	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	YES
Tennessee	IOU	ECAR	NO	YES	YES	NO	NO	NO	NO	NO	NO	NO	NO	YES
Utah	COOP	WSCC	NO	NO	NO	NO	NO	YES	NO	YES	NO	NO	NO	NO
Utah	DIS SYS, MUNI	WSCC	NO	NO	NO	NO	NO	NO	NO	YES	NO	YES	NO	YES
Vermont	IOU, PP	NPCC	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO
Virginia	IOU	ECAR	NO	YES	YES	NO	NO	NO	NO	NO	NO	NO	NO	YES
Washington	IOU	WSCC	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO
West Virginia	IOU	WSCC	NO	YES	YES	NO	NO	NO	NO	NO	NO	NO	NO	YES
Wisconsin	IOU	MAPP	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	YES

Cont...

State	Type of Organization	Reliability Council Region	15A	15B	15C	15D	16A	16B	16C	16D	16E	16F	16G	16H
Wyoming	IOU	WSCC	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO
Wyoming	IOU	WSCC	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO	NO

Key of Abbreviations					
IOU - Investor Owned Utilities	COOP - Cooperative	PP - Power Pool	SYS - System	DIS - District	MUNI - Municipal

Questions:

(15) Does your generation planning routinely take into account:
- (a) Existing or anticipated generating capacity in neighboring utilities
- (b) possible purchase from or sales to other utilities within the state
- (c) possible purchase from or sales to other utilities outside the state
- (d) possible cogeneration and small power production in your service area

(16) Does your transmission planning routinely take into account:
- (a) the regional power grid
- (b) the transmission needs of your state as a whole
- (c) rural electric cooperatives and municipalities in your service area
- (d) cogenerators and small power procedures in your service area
- (e) the need for transmission facilities to better use existing generating capacity
- (f) the need for transmission facilities to better use planned generating capacity
- (g) the possibility of using new transmission capacity to defer generating additions
- (h) the possibility for wheeling transactions

The following section of the report summarizes the generation/transmission planning and coordination practices of the respondents to the personal interviews administered to utility executives during the data collection phase of the National Governors' Association study on electric transmission planning and coordination. Responses are summarized for Interview Questions # 1, 2, 3, 4, 5, 12, 13, 14, and 20, and where appropriate incorporate references elsewhere in the interviews as indexed by embedded concept. Topics 1-8 as identified in the preliminary work plan are those presented below. Topic 9, a regional tabulation of transfer capability where reported, proved impossible to provide. Topics 10-15 are addressed in the materials summarized for the first eight topics.

PLANNING AND COORDINATION OF TRANSMISSION AND GENERATION

Interview Question #1 asked respondents to describe their company's planning process for the assessment of need and construction of transmission facilities and generation facilities. Responses indicate that companies utilize by and large the same planning process throughout the industry. Interview Question #2 asked how transmission and generation planning are coordinated. This planning and coordination process is described below. Additional notes of interest on aspects of generation and transmission planning are provided thereafter.

Typical Generation and Transmission Planning Processes

Investor Owned Utilities

The interview responses reflected clearly that generation and transmission planning are integrated and iterative in their execution. Generation and transmission planning is typically conducted by one department within the organizational structure of an electric utility; one respondent indicated that generation and transmission departments, while separate entities, reported to a common supervising entity. The interview respondents indicated that a typical generation and transmission planning department may be involved in some distribution planning as well.

Those utilities engaged in generation and transmission planning remarked that the load forecast developed for a utility is the "driving force" behind generation and transmission planning. Many utilities noted explicitly that it is artificial to separate generation and transmission planning--that they are part of an integrated process. In general and speaking theoretically, IOUs remarked that the company's first focus in generation and transmission planning is on the obligation to serve: hence the focus on determining the amount of generation required to service load, followed by the determination of the optimal means of delivering generated power to load via transmission. One respondent noted that generation and transmission planning must be oriented primarily toward meeting one's own load because of regulatory requirements that planned facilities be demonstrated to be used and useful to in-state citizens or consumers.

Transmission planning may, however, alternatively be driven by a concern to maintain or enhance reliability in the absence of new capacity. Since many of the utilities interviewed are in capacity-rich circumstances, they have not been in a generation planning phase for some time. Under these circumstances, transmission planning is associated with the maintenance or improvement of reliability of service. Still, transmission planning which is driven by a reliability concern and is not associated with the delivery of planned generation is generally in response to load growth within a utility system.

The determination of load for a utility system is an effort that generally takes place annually. Load forecasts are made for a long-range period, ranging from ten to thirty years. Load forecasting generally takes into account such variables as weather sensitivity, demographic and economic growth, and price effects. An econometric approach to long-term forecasting was utilized by the majority of respondents.

Once a load is determined for a utility system, the next step is to determine whether supply (generation and purchased power) is sufficient to meet load, given generation reliability requirements. A variety of options are generally considered upon determining that load requirements will not be met under current conditions. Several respondents noted in this context that demand-side considerations are weighed on a cost-benefit basis along with supply options to balance load and supply. A variety of possible ways to match supply and load are considered, taking into account criteria such as reserves, forced outages, load variations, unserved energy probabilities, loss of load probabilities, and financial considerations. The criteria to be taken into account may vary by company, but in all cases the point of the exercise is to develop an optimal supply plan for the utility.

Many companies utilize production costing and generation expansion software (examples cited were AEGIS, ProMod and ProScreen) to take account of the integration of new generating facilities into an existing network. One respondent noted that the most important thing you get out of such programs is a suggestion as to what is the proper time to make a decision on the type of generation required and the amount. Location of generating facilities takes additional analysis.

Transmission planning follows the planning of generation. The question of where transmission is required to serve demand is a function of existing generation and transmission facilities. At issue is the minimization of cost of both generation and transmission to get the supply to the load.

Subsequent to the development of a long-range aggregate demand forecast, a detailed location-by-location, bus-by-bus forecast of anticipated demand is prepared to ensure accurate input to models which are used to simulate load flow and to assess system stability. It is necessary to anticipate production costs of generating facilities in the execution of such testing, since generation must be dispatched in the course of load flow simulation.

Transmission system simulation is performed with specific contingency criteria governing the acceptability of simulated system performance. Performance criteria are established by the Regional Reliability Councils, by other coordinating bodies of which utilities are members, and by individual utilities themselves. If transmission system simulations reveal potential problems with thermal loading of lines or voltage limitations, transmission planners determine the best way to resolve the situation. Measures taken may include changes in operating procedures, changes in the dispatching of generation, system reconfiguration, or construction of facilities.

The extent of coordination with other utilities during the generation and transmission planning process is determined by the degree of mutual benefit that can be enjoyed as a result of such coordination. The degree of potential benefit determined is a function of the extent to which other systems are taken into account in transmission system planning. Because of the characteristics of ac flow, the effect of neighboring transmission systems on transmission is taken into account "as far as you can detect problems", in the words of one respondent. Joint load flow studies conducted with neighboring utilities permit the identification of potential problems in a simulated transmission system.

For any given generation or transmission project, there is an "appropriate" level of coordination. A project may involve only one other utility, or it may involve all the member utilities of a Regional Reliability Council, or several Councils, depending upon the scope of its impact. Generally, in situations where a utility is interconnected with a neighboring utility, formal interconnection agreements exist which set forth the conditions of coordination of investment, reliability, adequacy, energy interchanges, and so forth. Construction of a major facility in New York State may be reviewed, for example, at five levels: the company, the New York Power Pool (NYPP), the NPCC, the MEN interregional study group, and by the New York Public Service Commission.

The forums in which mutually beneficial projects are generally discussed are the Regional Reliability Councils and their sub- and inter-regional components. As one respondent put it, "When the need is there for reliability elsewhere and it can be shown to be mutually advantageous, then obviously the parties enter into it". Another respondent from MAIN indicated that the Reliability Council is the site of information exchange: "That's where knowledgeable planners meet". As the Regional Reliability Survey responses indicate, the Regional Councils regularly conduct regional and interregional studies of planned transmission system performance to detect loading and voltage problems, and communicate the results of such studies to their members under terms of the Council Agreement.

One respondent indicated that transmission is needed for three reasons: 1) to serve the load, 2) for reliability, and 3) to interconnect with other utilities, for reliability. "To the degree you can use the interconnects for economics, then you want to do that."

Although transmission planning was described primarily as a logical follow-up to generation planning, many of the IOUs interviewed described themselves as in a capacity-rich situation presently; hence transmission planning is presently in response to service area load growth which requires the upgrading of transmission facilities to higher voltage capacities. Several respondents indicated difficulties in securing approval from their respective regulatory bodies for transmission facility projects which only served to strengthen system reliability rather than to tie in generation. Several utilities in WSCC remarked that transmission planning is increasingly taking into account the potential to market excess energy.

Joint Action Agencies/Power Brokers

Five utilities were interviewed which are organized to provide power through purchase and/or generation to their constituent members, either municipal electric systems or rural electric cooperatives. The coordination of generation and transmission planning differs from that of IOUs because of the limited generation capabilities/requirements of these utilities. Joint action agencies depend upon the load forecasts of their members, and upon projected power supply costs of their major suppliers in instances where they own no generating capacity of their own. The potential ownership of generation and/or transmission facilities is evaluated on the basis of projected power supply costs of suppliers.

Additional Comments of Interest

Incentives for Displacement of Generation with Transmission

A large midwestern utility noted that a quick payback would be required to invest in a transmission line which would permit relatively inexpensive power to be transmitted to load in lieu of building new generation. The same respondent indicated that in any event payback periods were not used in his company's economic analysis; instead the present value of revenue requirements over the first ten years of a facility's life was used.

MAPP Generation and Transmission Coordination

Utilities which are members of MAPP stressed that generation and transmission planning were coordinated first through the MAPP Design Review Committee.

NPCC Generation and Transmission Coordination

NPCC member utilities were interviewed from both the New York Power Pool (NYPP) and the New England Power Pool (NEPOOL). These utilities stressed the high degree of generation and transmission coordination required by NPCC, NYPP, and NEPOOL: each requires transmission planning to be accepted by consensus. NYPP members must also have their generation and transmission plans approved by the state of New York.

The transmission planning of Vermont's electric utilities is coordinated by Vermont Electric Power, a single purpose transmission company. A coordinated transmission function provides significant advantages over distinct and separate transmission department in each distribution company in streamlining and expediting the process of transmission planning and construction.

Informal Coordination Groups

One respondent noted the presence in Indiana and Illinois of informal coordination groups among utilities, in addition to the more formal modes of coordination available via bilateral agreements and the formal entities comprising the Regional Reliability Councils and their sub-regional aspects.

Coordination in a Competitive Environment

One respondent representing an IOU suggested that a more competitive environment envisioned by proponents of open access would lead to less cooperation and coordination among utilities than presently exists.

WSCC Generation and Transmission Planning

Several aspects of generation and transmission planning among utilities in WSCC are noteworthy. Two utilities interviewed (one IOU and a federal power marketing agency) plan in conjunction with the Northwest Power Planning Council, which prepares a regional forecast and requires its member utilities to consider all power supply and demand-side options in the planning process. It was remarked that the dependence on hydro power in the Northwest makes necessary a significantly greater degree of inter-utility cooperation.

Several of the utilities interviewed from WSCC are high avoided-cost utilities, dependent upon gas as a fuel for generation. One of these stated that it has conducted customer surveys to determine the cost of unserved energy. Each of the high avoided-cost utilities noted that their circumstances had spurred the development of numerous QFs and small power producers, which posed challenges for transmission planning. QF and small power production has encountered local bottlenecks which have hampered their incorporation into utility transmission networks.

Utilities in WSCC were apt to mention that transmission planning took into account the building of lines to provide access to the market for excess energy.

Interview Question #3 asked respondents to describe some of the difficulties encountered in coordinating and pursuing joint transmission facility projects with other utilities. The following summary contrasts the responses of those utilities owning significant transmission facilities and the responses of those utilities without significant transmission facilities. A description of differences apparent among the reliability council regions and exceptions to the summary statements concerning utilities with transmission facilities and those without them is included.

Difficulties with Coordination and Joint Facility Projects: Perspectives of Utilities with Bulk Transmission Facilities

The most common responses of utilities owning transmission facilities were that no difficulties were encountered in coordination with other utilities or in pursuing joint facility projects, or that the problems encountered were those to be expected in any negotiation process. Of the 35 entities interviewed, 10 indicated there to be no particular difficulties in inter-utility coordination or in the pursuit of joint facility projects: of these, 6 are investor-owned utilities, three are federal or state power authorities, and one is a joint action agency. Difficulties inherent in the negotiation process were cited by 14 of the respondents: eight of these referred explicitly to difficulties in reaching consensus on anticipated benefits and associated costs to be borne by partners in joint facility projects, and six (each from the WSCC) commented on difficulties inherent in accommodating the requirements of numerous and diverse parties to a proposed joint facility project.

For the most part, utilities owning bulk transmission facilities describe their difficulties in pursuing joint transmission facility projects as routine. Some emerge in the course of negotiation and reflect different assessments of the respective benefits (and associated costs) of the facilities being discussed. Estimation of costs and benefits over time, and the assignment of costs over time is problematic in the course of negotiating a joint transmission facility project. However, such differences in the assessment of shared costs are expected in the course of business. As a representative of an IOU in NPCC noted, "Once you start talking about money, we have some difficulties negotiating sometimes, and we snarl at each other a little bit and drive hard bargains and so forth, but I think in the end we've worked out pretty well being able to share in joint facilities/transmission projects equitably." A representative of an IOU in ECAR commented: "The mechanism is negotiation -- two organizations who recognize that there's a common goal to be achieved and that's reliability and economy of power supply to their respective customers. And the fact that each party in the interconnected system affects each other party in the interconnected system, makes the common goal that we all had better work together, otherwise we're all going to go down the tubes together."

Difficulties in assessing respective benefits of a facility over time in order to determine appropriate respective costs were clearly articulated by a representative of an IOU in MAPP. "What we may perceive as an equitable balance a few years ago may not turn out that way. Those realities have surfaced with new facilities that we've planned. Time really complicates the planning and distribution of benefits of mutual facilities....Two substations were needed by two utilities. One utility would build one and other other utility would build the other. What we perceive the loading to be when those units were put in service did not materialize. One utility had to upgrade the size of the transformer because the other utility had greater load growth than what was perceived. So that would tax the constructing utility more than the first. That transaction would be recalled and re-examined. So when a third substation needs to be built, the history of this process has complicated those negotiations."

Other routine problems mentioned include "the run of the mill regulatory, permitting and intervenor problems one sees in any part of the country" (an IOU in NPCC), and the reluctance of regulatory authority to approve a facility which transmits power through an area without directly benefiting its residents. Obtaining right-of-way was cited as a problem in joint facility projects, particularly if a line will not serve the needs of the immediate population. An IOU in WSCC noted in regard to regulatory authority reluctance to certify a line not directly benefiting a state that as a result such a transmission line would be modified to interconnect with everything that it crossed.

Other difficulties were cited less regularly which appear to be not associated with the coordination or joint facility planning problems of specific reliability regions. An IOU in NPCC noted that, "With prudency becoming increasingly important, utilities in the future will be highly reluctant to take a risk on transmission projects, if there is even a remote chance that they may turn out to be uneconomical." An IOU in SERC pointed out that more joint facility projects might go forward if savings accruing from those projects were provided as an incentive to the participating utilities rather than flowing in their entirety to utility customers. An IOU in ECAR noted that while utility coordination presented no problems, the emergence of a more competitive atmosphere in the electric utility industry will serve to hamper coordination in the future, particularly in an open transmission access scenario.

Several respondents noted the differences in corporate goals/philosophies and in the perceived optimal timing of joint facilities have hindered the pursuit of joint projects in the past. An IOU in SERC stated that the demise of the CARVER power pool, which was formed in 1967 and dissolved in 1970, resulted from: 1) differences of opinion among member utilities as to reserve levels required; 2) differences over capital and construction considerations involving planned nuclear units; and 3)"special deals" required by member utilities in return for their participation in joint projects. A municipal utility in WSCC noted that "Two utilities might agree that a transmission element is good and necessary, but they might be ten years apart in their need for it and have difficulty agreeing on building."

Other non-region specific problems noted by respondents to Interview Question #3 owning transmission capacity included: "spoilage" of tax-exempt status of a project by the participation of utilities not enjoying such a status (a municipal utility in WSCC); concerns of potential partners with the release of proprietary information (an IOU in WSCC); the history of IOU-muni relationships, and the remaining distrust that previous lawsuits have engendered (an IOU in WSCC); the inexperience of "new players" such as munis and joint action agencies in the "power game" (an IOU in WSCC); and problems associated with the regulatory requirements of multiple state jurisdictions in the siting and certification of transmission facilities (2 IOUs and 2 federal power authorities in WSCC: see below for anecdotal information).

Observations of Differences in Responses by Reliability Region

Although most of the difficulties encountered in coordination and the pursuit of joint facility projects are not region-specific, respondents from WSCC noted several difficulties which result from the geography of the WSCC region and the resulting configuration of lines and parties to coordination and joint facility projects. These difficulties are noted below, along with the few region-specific remarks on coordination and joint facility project participation to be culled from the interviews.

ECAR

An IOU in ECAR stated that principles for cost-sharing of planned joint facility projects were well established in its experience. The respondent explained that such projects were regularly carried out with the same two or three partners, and that this provided for the achievement of consensus on the estimation of benefits and associated costs.

NPCC

An IOU from NPCC remarked that membership in the New York Power Pool facilitates coordination among utilities.

WSCC

Three problems were identified by a majority of WSCC transmission owning respondents which appear to be exacerbated by the geography of the region: difficulties inherent in the coordination of numerous utilities with differing needs and objectives participating in joint facility projects in WSCC; difficulties encountered in certifying and siting transmission lines which cross state borders; and difficulties associated with loop flow. Ten utilities owning transmission lines were interviewed from WSCC; eight of these mentioned problems associated with numerous project participants, six of these referred to the difficulties associated with meeting the regulatory requirements of differing state jurisdictions in regard to line siting and certification, and four referred to problems associated with loop flow.

Specific projects were referenced in several cases which have been hampered by the participation of numerous participants. The Inland Intertie Study was mentioned by two IOUs in the region as manifesting coordination problems among its 27 or 28 participants
(these numbers were provided by the two respondents). One of these respondents noted that the Inland Intertie participants have different objectives: some want to "slice" the line up such that they have capacity in both directions; some prefer it to act as an interconnection, where the northwestern utilities own their end and the southwestern utilities own the other end. As far the the product or service provided by the line, some are looking for diversity

exchanges, some for energy, some for capacity. Some southwestern utilities have expressed the concern that once the line is in place the northwestern utilities will go after their customers. "Right now, you have too many interlocking regulatory processes and too many misaligned competitive situations."

Several utilities provided anecdotal information on difficulties ensuing from differing regulatory requirements of states in which joint projects were planned. One IOU spoke of a 345 kV line that was proposed between Alamosa, Colorado and Taos, New Mexico. There were to be four partners; to avoid having to certify in each state, the Colorado partners would build from their end to the border and the New Mexico partners would build from the border to the load center, which was the site of molybdenum mines and refineries. The Colorado utilities were interested in the line for reliability purposes; the New Mexico utilities were trying to serve the load. With a downturn in the steel industry, however, the load disappeared. The Colorado utilities still wanted to build the line, but the New Mexico PSC saw little justification for it, particularly in light of financial constraints on a New Mexico partner. The New Mexico and Colorado partners tried to work out a firm purchase to help justify the line, but the deal fell through since the Colorado partner secured a more economical source in Wyoming. The Colorado partners continue to view the project favorably as right-of-way and environmental impact concerns are met; the line would also alleviate the region's loop flow problems to some degree. But until the New Mexico PSC approves New Mexico utility participation, the project is delayed.

Several utilities mentioned the differences in Arizona and California regulatory requirements as problematic. A state power authority noted that projects with California utilities were complicated by the latter's requirement to have approval of the California Energy Commission to put a project into rate base. A California IOU, on the other hand, stated that, when considering its participation in proposed additional units at Palo Verde, the Arizona regulatory agencies assumed that the California regulatory agencies would "impose their wisdom" on Arizona and make sure that everything would be done by California standards. This respondent asserted that a lack of uniform siting and certification requirements slows or kills projects because the various state commissions each try to protect their jurisdiction,
stature and authority. Another Arizona IOU noted that differences in California and Arizona regulatory standards had complicated the Palo Verde to McGell transmission line project.

Another illustrative anecdote shedding light on interstate regulatory problems was provided by a federal power authority. Itself, a cooperative and an IOU were involved in the planning of a 230 kV line from New Wonderwood to Miles City, Montana and from there through North Dakota. Due to North Dakota siting requirements, it was agreed that the North Dakota partner should build the line from the North Dakota border east: the out-of-state participants determined to not become involved in a proceeding with the North Dakota regulatory boards. As a result, line ownership and shares of costs were split at the border.

In regard to the problems associated with loop flow which impact on utility coordination and joint facility pursuits, one IOU stated without elaboration that the installation of phase-shifters in weak-link areas might adversely affect new transmission projects; another stated that loop flow is presents a difficulty in that it robs transmission lines of their full capacity, thus complicating the determination of anticipated benefits and associated costs to be borne by project partners. Another respondent noted that because of the loop flow phenomenon, new transmission projects threaten to diminish individual utility rights in existing capacity.

An IOU provided an interesting anecdote illustrating the complicating aspects of loop flow on utility coordination. The respondent is one of the participants in the California-Oregon Transmission Project (COT) and has been experiencing problems related to loop flow and reliability. The COT project is a 350 mile, 500 kV ac line from just over the Oregon border to the Bay Area. It is scheduled for completion in 1991 and should provide 1600 MW from the Northwest. The loop flow and reliability problems have stemmed from the tripping of a transfer relay on one of two existing 500 kV lines from Oregon to the Bay Area, which has caused a sympathetic tripping of the other line and a resulting "islanding" of California and Arizona on several occasions. The Arizona utilities have become dissatisfied with the amount of underfrequency shedding experienced as a result of the tripping, and support the COT because it will decrease the chances of load shedding. The Arizona utilities wish to decrease the chances further by having the COT line sited away from the two existing 500 kV lines. While the COT participants concede the wisdom of separating the new link, because of the mountainous terrain and environmental issues, it would be more expensive to find and construct an alternative route. Environmentalists want the line to parallel the existing two. This controversy has slowed the project. Meanwhile, a 345 kV line planned by a northern Nevada IOU and a municipal located in the respondent's service area which would carry 400 MW has been suggested by the California PUC as an alternative routing to the COT participants. At the time of the interview, this suggestion was under study.

Several other difficulties in utility coordination and joint facility pursuits were mentioned by WSCC utilities owning transmission facilities. One IOU remarked on the difficulties encountered in siting transmission facilities over Indian reservation land; a municipal utility stated that problems arise from the lack of true regional planning, as opposed to the reactive planning that occurs when one utility announces its intention to engage in a project; one IOU noted that federal restraints complicate negotiations with federal power authorities; and an IOU mentioned the complications required by the filing of "friendly lawsuits" to establish that municipal partners are obligated for their shares of proposed joint facilities.

Difficulties with Coordination and Joint-Facility Projects: Perspectives of Utilities Without Bulk Transmission Facilities

Of the nine interview respondents not owning bulk transmission facilities (or not having obtained such ownership until recently), only one indicated there to be no problems in inter-utility coordination or in the pursuit of joint facility projects: a co-op in SPP. The other respondents voiced similar concerns which included bulk transmission facility owners' denial of ownership of bulk transmission facilities, or the denial of such ownership at reasonable prices; denial of wheeling access, or denial of access at reasonable prices; the reluctance of bulk transmission owners to enhance the reliability of service to radially-served entities; and general charges of harassment by the investor-owned utilities. These comments and others more specific to reliability region or to the status of particular respondents are provided below.

Three respondents stated their experience of having been denied ownership of transmission facilities, either outright or at what were perceived to be reasonable prices, having such ownership delayed. A joint action agency serving customers in MAIN and MAPP stated, "The state's private suppliers have in the past and continue to deny...[our]...requests to buy a pro-rata share of existing transmission facilities at reasonable prices, or even to buy into new transmission facilities on a reasonable basis. In their rates, wholesale customers have paid for their share of the costs, including a profit return, of putting the existing transmission grids in place...[Our] primary obstacle to adding transmission facilities is coordination with other utilities--in particular, their exercise of monopoly power through the ownership of the bottleneck resource of transmission in their control areas."

A co-op in SERC stated, "I think where our particular systems have been left out is that we have not been permitted, until these current negotiations...,to own our share of the bulk facilities, and that has kept us from being able to coordinate generation planning." Another co-op in SERC stated that the "companies have been reluctant to work with a co-op." It was related that the co-op had tried to obtain an interconnection and wheeling arrangements for a number of years with Gulf Power Co., but that they had declined to work out any agreement. When at last the co-op sought to build transmission to serve customers in the Florida Panhandle, Gulf Power filed a petition before the Florida PSC to prevent the building.

A municipal power agency in MAPP described its consideration of alternatives to obtaining integrated transmission agreements in instances where the wheeling charges are perceived to be unreasonable. "The alternatives that we most seriously look at are integrated transmission systems. In other words, we want to buy our fair share of the system that is being used to deliver to our members. Ottertail's been cooperative, NIPCO's been cooperative, NSP has been cooperative but very, very slow.

A generation and transmission cooperative in WSCC stated that Utah Power and Light has not been willing to do joint ownership and planning for lines inside Utah. "As far as joint planning, joint use of lines, or joint right-of-ways to reach neighbors through them, where we would also be reaching our own loads, there's been no agreement."

Another joint action agency related an anecdote illustrating its difficulties in dealing with Utah Power and Light. The respondent serves a number of customers in a county which is served by a radial system owned by UPL. Due to load growth in the early 1970s, the respondent asked UPL to upgrade existing lines and build some new transmission into the area, in accordance with provisions of the wheeling contract which require the wheeler to upgrade existing lines to meet the capacity needs. The wheeler continued to delay the upgrading; by 1984-1985 the growth was about 7 MW/year, a rate which approached overloading the system. the respondent informed UPL that they wanted to build a transmission project and asked UPL if they would like to participate. UPL declined. After the respondent filed to obtain right-of-way with the Bureau of Land Management (BLM) and the Forest Service in 1985 , UPL filed a competing and nearly identical application.

The BLM then acted as a "lead agency" and attempted to coordinate the applications. BLM concluded that a joint project would be best but UPL refused. UPL also refused to let the respondent participate in UPL's line if the respondent gave up its line. "It was them or no one that was going to build the line according to Utah Power and Light." The respondent asked the BLM and the Forest Service to go through a joint NEPA process on both proposed lines. The respondent did an environmental assessment on its line which was basically paralleling an existing 500 kV dc line, so some work was already done. The assessment revealed no significant impact , thus an environmental impact statement was not required. There were no challenges on environmental issues. The BLM and the Forest Service had similar findings on UPL's proposed routing. However, the County Planning Commission and the Forest Service did not want to give up a few spots on UPL's route: the line would be going through a proposed wilderness area.

BLM became frustrated with the process and requested, by a series of letters, for the State of Utah to resolve the problem. There was no mechanism within the state to settle the issue, however. A quirk in the Inter-Local Act required the respondent to get a certificate of convenience and necessity before building transmission or generation, the law's intention being to provide condemnation rights outside of municipal boundaries. UPL had no requirement for certificate; they needed only to request their annual expenditure and construction budget.

The respondent suggested to BLM that this requirement might be a vehicle for the state to address the controversy through the PSC. The PSC thought it unfair that the respondent had to obtain a certificate while UPL did not for a similar project. The PSC therefore changed "Rule 90" so that "any expenditure over x million dollars on transmission or generation would require a special certificate." UPL and other utilities challenged the new rule. But the PSC strongly wanted UPL to obtain approval from them to build the line or to face PSC imposed constraints. In December of 1985 the respondent applied to the PSC for a certificate on their proposed 345 kV line. UPL intervened in the hearing, allegedly without making any real case or arguing about their own requirement to get a certificate. UPL used its Shareholders' Association to argue about the constitutionality of the Inter-Local Act and "all sorts of ideas."

The hearing, the largest in Utah PSC history, ended in August 1986; it generated 8,500 pages of transcripts. The respondent spent about $500,000 on consulting engineers, had right-of-way purchased or secured, knew what the line would look like, where it terminated, and presented a 6-volume conceptual design to the PSC. UPL provided sketches of its proposed line with no details of conductor size, line configuration, or right-of-way. "They were just definitely trying to delay and kill the project from our perspective." UPL then sued the respondent in the Third District Court, arguing that the respondent could not contract for power. The lawsuit cost the respondent over $1,000,000.

There was still no decision made on the line as of the interview. Because of the delay, one of the respondent's members had to install 14 MW of diesel-fired generation to stay on line and serve their customers. As of the interview, the respondent was asking for an order from the PSC for UPL to upgrade the 69 kV line serving the area immediately, "even though it could be detrimental to our long term plans in building a non-radial system into the area. It's that desperate."

Experience with denial of access or of "fair" wheeling rates was communicated by four respondents. The joint action agency in MAIN and MAPP described Northern States Power's unwillingness to negotiate a firm transmission rate with them. "They claim a physical constraint, that their line is loaded. We don't know. In their calculations they include all of their actual transactions plus their potential nonfirm transactions ahead of what our firm transaction would be."

A municipal power agency in MAPP related that Iowa Public Service had refused several years previously to wheel power to one member
in the IPS service area. "We didn't push the issue because of the fact that our rates were higher at the time than IPS's rates. Now we've developed a new marketing rate to this one particular member and our rates are lower than IPS and they are no longer saying that they are refusing to wheel -- we asked them six months ago and they're dragging their feet."

A joint action agency/power broker in ECAR related that its wheeling arrangements with three separate IOUs were each the result of litigation. According to the respondent, however, the wealth of available capacity in ECAR has changed the attitudes of the investor owned utilities there over the last several years, and they have become more cooperative.

The same respondent mentioned that one problem which hampers the development of potential joint facility projects is that it has no legislative authority to pursue such projects on a tax-exempt basis.

SYSTEM CAPACITY AND OPERATIONS

Interview Question #4 asked respondents how their company measures transmission capacity. Many of the respondents asked the interviewers for a clarification of what was meant by "transmission capacity", and spoke of the differences in interpretation possible, even with respect to "transfer capability" and its various NERC-sanctioned definitions. Having established that the question was intended to get at how one determines what the limits of power flow from point A to point B are, respondents were quick to caution that transmission capacity is dependent upon a range of assumptions or exogenous variables which affect its measurement, e.g. seasonality, pattern of plant operation, relationship of generation origin to load, magnitude of flow, changes in system configuration, and off-system sales or purchases. Some respondents indicated that the dispersed nature of their interconnections or their status as members of an economically dispatched power pool rendered meaningless any calculation of intrasystem transfer capability; others provided numbers for intrasystem transfers at specific interfaces, with the caveat that these represented the capacity to transfer power from one specific point to another, and in one direction only, under specified conditions. Import and export capacities are not equivalent: one IOU in WSCC stated that its system was designed to import power, and that exporting power "presents new problems with stability and power angles."

Difficulties in question interpretation are summed up by the response of an IOU in ECAR. "We really can't develop a single number for transfer capability. One could add up the capacities, the arithmetic sum of the capacities of all of the facilities that are part of our interconnections to neighboring companies,...but that's not a meaningful number per se. Really the meaningful analysis is the ability of the total system operating as part of the interconnected environment to be able to move power across that system or to neighboring company systems -- what we call the first contingency transfer network capability."

Limits for the transfer of power over a system are measured at different levels. A federal power authority in SERC provided relatively detailed information on the calculation of individual line capacity: it is calculated "by means of a computer program based on the IEEE method. It uses the conductor size and stranding, the conductivity of the conductor and its assumed emissivity, the crosswind, the relative direction and location of the sun to the line, the solar absorption factor, and the total radiated heat to determine a conductor temperature rise. This rise plus the ambient temperature must not exceed the temperature for which the line is designed."

As a representative of an IOU in NPCC pointed out, however, "usually what you are concerned with is not one line but a good line to network -- what we call an interface." Transfers of power across a utility system or between systems are limited not only by the thermal constraints of a line. As an IOU in NPCC stated, "interface limits...reflect the most limiting of three possible constraints: conductor thermal loading, the ratings of the transmission lines themselves; transient stability performance, the ability of the power system to recover when a fault occurs on the system and a disturbance is introduced into the system; and steady-state voltages, where the voltages on a transmission system may adversely be affected by heavy transfers of power across the state." The same respondent indicated that stability limits are the most constraining of these three, in his judgment. Another respondent from NPCC also indicated that stability constraints are generally more restrictive than are thermal limitations. Yet another respondent in NPCC indicated that the thermal limit test, the voltage drop test, and the stability test comprise "a pretty industry-wide and generally accepted approach to determining need for transmission."

Respondents professed adherence to NERC-established guidelines for the utilization of first contingency incremental transfer capability measurements in reporting: many provided FCITC values for specific interfaces of their systems with others. Several utilities spoke of a minimal acceptable transfer capability for import into their systems: a federal power authority in SERC reported its minimal acceptable transfer capability level to be equivalent to the largest unit on its system, although more was generally maintained, while an IOU in SERC reported that its import capability of from 2000 to 2500 MW was equivalent to the two largest units on its system. An IOU in NPCC indicated that its largest single contingency for the establishment of FCITC is the tripping of a 345 kV line with which it is tied to the North.

Transmission capacity is determined in two modes: in planning studies which are conducted semi-annually or annually and look ahead to the upcoming peaking season, and in real time. An IOU in ECAR reported that it defines transfer capacity by superimposing a postulated power transfer of some magnitude on a base load flow simulation. Power transfer limits are established iteratively, by varying postulated power transfers until such point as a system remains within previously established thermal, voltage, and stability limits. The modeling of system behavior under postulated power transfer scenarios requires numerous assumptions about system component configuration and inter-system effects engendered by power flow in connected systems.

Such planning studies provide guidelines for day-to-day system operation. An IOU in WSCC stated that transfer capability limits at interfaces within the region are in effect "symbolic" of loading conditions on the system. Transfer capability actually changes day-to-day as a function of operating conditions. An IOU in ECAR stated that day-to-day transfer capability "really should be available on a daily basis and there are techniques being developed which will allow us to do this in the future."

Several of the responding utilities (members of the Florida Coordinating Group, NYPP, and NEPOOL) indicated that they have the technical capabilities in place to monitor transfer capability in real time. In Florida, one member utility is designated as an "import coordinator", responsible for monitoring transfer capability on a minute-to-minute basis. The NYPP operator "basically has the real time data on the system, conducts contingency analysis and basically sets limits on all of the lines to maintain a secure system able to withstand first contingency. So its a minute by minute assessment and monitoring." Through NEPEX, NEPOOL carries out a similar real time monitoring function.

Utilities are generally interconnected with their neighbors at many points, and the non-simultaneous capacity of specific interfaces to transfer power under assumed conditions varies widely among these points. A federal power authority in SERC is interconnected at 30 points; transfer capability ranges from 220 to 2000 MW among the interconnections. Transfer capabilities vary among interconnections of an IOU in ECAR from 350 MW to "maybe" 2000 MW. An IOU in WSCC is interconnected at over 200 sites over a widely dispersed area; since its transmission planning is dependent on regional design, it does not even assess the individual transfer capabilities of each of its interconnections. A state power authority in WSCC stated that since its transmission system is tightly interconnected with other utility transmission systems, the establishment of an intrasystem transfer capability would have little meaning.

Import capabilities are of more concern to utility planners than export capabilities, it would appear: an IOU in SERC stated that "our import capability is what we are concerned about because that's going to indicate whether or not we can survive certain contingencies. If we can only export so much that is someone else's problem, not ours." Some respondents provided the import capabilities of their systems. Several IOUs in SERC indicated that 3200 MW could be transferred from the Southern System into Florida under first contingency conditions; export from Florida would be limited to 1300 MW. Another SERC IOU indicated its import capability to be 2000 to 2500 MW, although it has imported over 3000 MW in the past. An IOU in MAIN stated that it could import from 4000 to 6000 MW. Another IOU in ECAR indicated that it could impart from 3000 to 4000 MW from the South, and another 2000 MW from Ontario, although problems in Ontario involving the construction of Bruce nuclear plant transmission facilities have lessened the latter. An IOU in WSCC indicated an import capability of 1100 MW.

Several utilities reported intrasystem transfer capabilities. An IOU in WSCC indicated that it could transfer approximately 1000 MW from North to South in its service area, but that South-North transactions were limited by the effects of the Southern California Edison system. Another IOU in WSCC stated that "the [intrasystem] number can range from 1000 to 1600 [MW] and you don't know what the hell is going on, what capacitors are in, what reactors are in, what's flowing where.

The loop flow phenomenon requires utilities in WSCC to plan their transmission system with loop flow effects in mind. A municipal utility in WSCC indicated that a purchase or sale by entities connected to the Pacific Intertie or located to the East could have a 200 to 600 MW impact on the municipal utility's transfer capability. An IOU in WSCC voiced its opinion that the use of phase shifters would have a deleterious effect upon transfer capability.

Interview Question #5 asked respondents how their companies measure the reliability of transmission facilities and generating facilities. Respondents described the role of the Regional Reliability Councils in setting minimum standards for reliability in their respective regions; these standards are described in detail in the section of this report on Regional Reliability Council organization and practices. Summarized below are remarks on reliability measurement complementary to the practices summarized in that section of the report. The summary is organized on regional basis.

ECAR

Four investor-owned utilities and one municipal joint action agency/power broker were interviewed from the ECAR region.

The transmission reliability criteria utilized by the IOUs stem from ECAR criteria. Contingencies to be tested are defined on the basis of sound planning principles. One utility reported that its basic transmission criteria is a multiple contingency test, in which one facility outage is specified, and a subsequent loss of a facility is simulated which would stress the system most critically. The same utility reported that its generating reliability is measured on the basis of dependence on supplemental capacity resources (DSCR): how often the system has to call on support from interconnected neighbors, or use short-time emergency capacity. If such support is provided between ten and one hundred times per year, additional system capacity may be required.

Another IOU interpreted the question from the perspective of the monitoring of generating and transmission facility availability. It uses the NERC GADS system, and an internal system GEARS (Generating Equivalent Availability Reporting System) to measure generating unit availability "as to whether they are off-line or restricted in their output, what component is causing the restriction and what is causing outages." A group within the company keeps track of transmission and distribution facility availability, annually reviewing statistics for the previous five years to see if any trends are developing, including customer outage trends.

A third IOU reported that it uses load flow, transient stability and short circuit programs to examine the performance of its transmission network. Such studies are often performed on a joint basis with other interconnected companies, it reported. While the IOU heeds ECAR reliability requirements, it also sets its own transmission reliability standards, spelling out "the kind of contingencies that we want to be able to provide for", and it assesses its own generation requirements internally. No more specific information was provided on the company's internal reliability criteria.

A fourth IOU reported that it utilized multiple generation criteria, including loss of load probability (LOLP), reserves, and capacity margin. It also referenced the multiple contingency standards of ECAR transmission reliability determination.

The municipal joint action agency/power broker owns neither generation nor transmission facilities; hence it interpreted the question to inquire how it assures reliability of supply to its customers. This respondent noted that its member wholesale customers have their own reliability criteria. It attempts to provide for reliability of supply to its members by requiring notice of interruption clauses in its contracts with power suppliers. These arrangements allow outages of three days, given sufficient notice, with costs for service restoration passed through the the respondent. After three days' outage, the respondent is free under the terms of the contracts to obtain power elsewhere.

MAIN

One IOU from MAIN was interviewed, as was one municipal joint action agency. The latter owns neither generation nor transmission; it provided no response to the question.

The IOU indicated that it utilizes a generation reliability criterion of one day in ten years LOLP, and that its transmission reliability is assessed on on a double contingency basis.

MAPP

Three utilities from the MAPP region were interviewed: two IOUs and one municipal power agency. Regarding transmission reliability assessment, the two IOUs stated that they did not measure transmission reliability independently: MAPP is responsible for transmission reliability assessment. However, each IOU indicated that it monitors and reviews transmission system outage data. One of the IOUs stated that it maintains its own internal data base of transmission outages, durations, and causes for all system lines of 69 kV and above, and that customer outage data is retained to measure customer electric service reliability. The municipal power agency owns no transmission facilities, but mentioned in the course of the interview that MAPP is currently reviewing its generation reserve requirements in light of the consideration of the integrated assessment of generation and transmission reliability. "Currently, MAPP looks at these things independently, but there's obviously a relationship between generation and transmission -- so MAPP is trying to figure out how to do that." The municipal agency respondent also indicated that most companies in MAPP employ load flow analysis to see whether voltage can be maintained between 95% and 105% of its optimal level, or with a single contingency can be maintained between 90% and 110% of optimum.

Regarding generation reliability assessment, each IOU stated that it uses the NERC GADS system to determine its generating unit availability. Each respondent noted that MAPP's current reserve minimum requirement is 15%, part of which is spinning reserve and part of which is quick-start. The municipal respondent stated that MAPP conducts "surge testing" of generation facilities.

NPCC

One state power authority and four IOUs including one investor-owned transmission company were interviewed from the NPCC region. Each mentioned that it adheres at a minimum to generation and transmission criteria established by NPCC. One IOU indicated that a consistent data base is available for NPCC members which incorporates data on generating and transmission system availability.

Two of the IOUs are members of the New York Power Pool (NYPP). The NYPP has established further reliability criteria for its members which are more stringent than the NPCC criteria. In regard to generation reliability, NYPP criteria required an LOLP of 1 day in 10 years, which is equivalent to an installed NYPP requirement of 22% reserve margin. Transmission reliability assessment is based upon the loss of the single most critical element resulting in no loss of customer load.

One of the IOUs in NYPP was more specific than the other about its measurement of generation reliability. It maintains extensive statistics on the historical reliability of individual generating units for itself and other members of NYPP. These provide a basis for the projection of future generation availability in reliability studies. "In system studies, we calculate quantities such as reserve margin, LOLP, and expected unserved energy in order to project the relative reliability of generating sources in total."

The same IOU is in the process of developing an historical data base on transmission outages in order to better quantify the reliability of individual transmission facilities. "We expect in the future to do some work with transmission reliability calculations. The software tools available at present...are somewhat limited; as these tools are enhanced our transmission planning will become more oriented towards a probabilistic analysis."

Three IOUs which are NEPOOL members were also interviewed. Each mentioned with respect to transmission reliability assessment that its system was designed in accordance with NPCC criteria to withstand a worst single contingency with no loss of customer load. Generating reliability is required to meet the NPCC criterion of one day in ten years LOLP.

In addition to LOLP, one IOU indicated that it assesses what happens in system operation when capacity gets tight: to what degree are support from neighboring utilities, public appeals, voltage reductions, or rotating blackouts required. Measuring the frequency of these measures provides "some kind of measure of how well our system works in terms of how well our models can predict what is going to happen."

At the direction of its state Public Service Board, the transmission IOU interviewed is beginning to look at probabilistic measures of transmission system reliability, based on the cost of installing additional facilities versus the cost to society of losing load. In regard to measuring the cost of unserved energy, another IOU in NEPOOL described the difficulties inherent in obtaining such cost estimates through customer survey, noting that the timing of a survey with respect to actual outages suffered influences the value placed by survey respondents on the cost of unserved energy.

SERC

Three IOUs, one federal power authority, two rural electric cooperatives and a state coordinating group from the SERC region were interviewed.

A respondent from one IOU was interviewed with a respondent representing the power pool in which the IOU participated. Among the generation reliability criteria considered by the pool's Planning Committee are reserves (20-25%), forced outage rates, unserved energy, load variations, LOLP, and others. The pool's transmission system is tested on a double contingency basis to assess the possibility of cascading outages. Reliability testing requires the maintenance of detailed records on forced and unforced outages. Load flow studies are run with an "equivalated power grid." Stability and transient stability studies are also run.

Another IOU stated that its transmission system is planned to survive a single contingency with no loss of customer load. Detailed stability analyses are performed to assess the impact of more severe disturbances. This IOU's generation planning is done in conjunction with a statewide coordinating group, which plans the state's generation as if it were one big utility. LOLP is one of the reliability techniques utilized by the coordinating group in its statewide planning.

A third IOU interviewed indicated that it supplies generation outage figures to the NERC GADS system, which measures how reliable the system is. This utility monitors customer outage minutes as well and has as a corporate goal the reduction of the number of customer outage minutes experienced. The respondent also stated that his utility utilizes EPRI's Over/Under Capacity Model to determine an appropriate level of generation; it uses the figure of $3 per kW/hr as in input in the model as the cost on an outage.

The federal power authority interviewed provided little information on the measurement of reliability, apart from the fact that extensive historical outage records are maintained.

One of the coops interviewed stated that it was required to follow REA planning criteria when it submitted loan applications; the other noted that each of its members keeps detailed outage records.

WSCC

Six IOUs, two federal power authorities, one state power authority, two cooperatives, and one municipal utility from the WSCC region were interviewed.

One of the IOUs indicated only that it planned its transmission on a single criterion basis.

A second IOU stated that it is in the process of trying to move to a consistent reliability analysis of generation, transmission, and distribution systems by developing a probabilistic planning procedure based on expected unserved energy. It mentioned that it has reviewed probabilistic transmission planning programs developed by EPRI, Florida Power, and Georgia Power. The respondent is looking at distribution system behavior indices such as average service reliability, interruption duration, sustained outages, etc., since 90% of outages spring from distribution system problems. The respondent uses four criteria to assess generation reliability: LOLP of 1 day in 10 years, contingency loss of the two largest generating units; 12% reserve margin, and energy margin. The most severe of these at any given time is utilized as the generation criterion.

The same respondent has done extensive survey work on the value of energy to the customer, and has developed a generation planning model on the basis of the survey results. Full outage costs for all customers are estimated at $35 kW/hr, partial outage costs at $9 kW/hr, and intermediate outage costs at $18 kW/hr.

A hydro-based IOU stated that its criterion of an adequate power supply is 2 hours/year outage. It uses a single contingency criterion without loss of customer load as its transmission reliability criterion. Its formal generation reliability criterion is LOLP of 1 day in 10 years, but the respondent stated that this criterion is more applicable to thermal-based systems that it is to hydro-based systems; hence a complementary generation criterion of the loss of one critical unit is also used.

Another IOU stated simply that it uses the WSCC reliability criteria.

A fifth IOU indicated that it keeps extensive records on customer interruptions and outage rates of transmission lines; that it uses a single contingency criterion for the assessment of both generation and transmission reliability, and in addition a 20% reserve margin criterion for generation; and that it seeks to maintain a LOLP of a maximum of 2% of clock hours per year. This respondent is attempting to develop a probabilistic assessment of transmission system outages: it is trying to blend the probability of outage on a line with the load duration of the transmission line so as to result in a loss of load probability. "We've taken the traditional concept of load duration curve and applied it to a transmission system."

The remaining IOU interviewed stated that it utilizes a single contingency criterion for transmission reliability assessment; and that, while it had previously used a 20% reserve margin as a generation reliability indicator, it has recently adopted an LOLP standard under order of the California PSC. The LOLP standard has proven to be equivalent to a 15% reserve margin.

This respondent has been looking at the tradeoff between increasing transmission system reliability and increasing distribution system reliability. "When you take a hard look at what it costs to maintain [transmission] reliability and the associated criteria and hardware compared to what it might cost the customers to have a little bit lower level of [transmission] reliability, it is probably in [the customers'] best interest to compromise."

One of the federal power authorities interviewed stated that it utilizes the WSCC reliability criterion as well as its own. For transmission, the authority has established a permissible level of eight hours/year down time at any customer deliver point. It plans its generation on an LOLP basis of 1 day interruption in 20 years. This respondent indicated that it has been reviewing the issue of lower rates to wholesale customers through the provision of lower levels of reliability, that it has revealed its budget projections for the next 32 to 4 years to its customers, and that several utilities are interested in pursuing the topic further.

The other federal power authority interviewed stated that it employs WSCC and MAPP criteria. It also adheres to individual system criteria, one example of which was a requirement for x number of breakers in each substation.

One municipal cooperative interviewed stated that it adheres to WSCC criteria. Internally, it considers the frequency and duration of outages as indicators of transmission system reliability, and attempts to maintain a level of 3 or less outages per year, each outage of 10 minutes duration or less. At the level of 12 outages per year, or of an unspecified number of outages of greater than 10 minutes duration, the respondent invests resources to correct the problem.

The same respondent established availability targets to assess generation reliability internally. Small hydro facilities are targeted at 90% availability; reciprocating and internal combustion units at 95% availability; and large coal-fired units at one-year availability levels of 85% or more. Over a thirty year life, coal-fired units are expected to attain 65% availability.

A generation and transmission cooperative interviewed stated that it is in the process of building a data base of outage information, and that its generation reliability is measured on an hours-available criterion established by EEI.

Finally, a large municipal utility stated that it uses a single contingency criterion for transmission reliability assessment; and that WSCC runs double contingency simulations for summer and winter peaks and for light loading conditions of spring and fall. Generation reliability is assessed on a single largest contingency basis "from a spinning reserve standpoint" as well as on a LOLP basis of 1 day interruption in 10 years.

Interview Question #12 asked respondents to identify the weakest portion of their own transmission systems. The question is closely associated in many responses with Interview Question #14, which in part asked respondents to identify portions of the regional transmission system outside their own service areas which they wish were strengthened. The responses summarized below are those which are responsive to Question #12: intrasystem weaknesses. In some instances it was difficult to determine whether responses were identifying transmission limitations of an intrasystem or an intersystem nature; the reader should review this section of the report in conjunction with the responses to Interview Question #14. The responses are organized by reliability region.

ECAR

An investor-owned holding company reported that while a bottleneck within its system might exist on a particular day, for the long term it is satisfied with its present transmission capacity. "We've got adequate capacity to meet all of our foreseeable requirements and as a result, we have very little transmission under construction; nor do we forecast any new transmission over at least the next five years." The respondent indicated that it had considered building an ac line to go far enough to the East to provide reinforcements across the state of Pennsylvania; but it determined that a short distance reinforcement from Allegheny to Keystone would not suffice since bottlenecks to power flow to the East exist beyond Keystone.

An IOU stated that it has a transmission limitation in the middle south area of its service area near Marion, Ohio. "Some people would call it weak and some would say it would be less than desirable for reliability." The interconnection is being upgraded to 345 kV via a joint project with AEP. "We are interconnected with one utility and have a somewhat limited transfer capability. From time to time it might be classified as a limitation; an economic opportunity presents itself that we could buy or sell more to that utility, but we were limited by the interconnection capability -- we always have the ability to schedule through another interconnected utility with whom the power would be flowing -- it would be more of a nuisance." From the point of view of the respondent, the interconnection is being upgraded to enhance reliability.

Another IOU stated that "there are various places on our system where under certain conditions we do have problems. We do have to take some operator action to be able to operate the network safely and anticipate the next contingency." No further detail was provided.

Another IOU indicated that limits are specific to specific transactions.

The municipal joint action agency/power broker in ECAR which was interviewed has no transmission system.

MAIN

Two utilities from MAIN were interviewed: a joint action agency and an IOU. The joint action agency has no transmission system of its own. The IOU indicated that the weakest area in its transmission system was to be found in the northwest area of its service area, between the Byron nuclear plant and the rest of its system. Another weak area identified is cable lines in Chicago which have the tendency of overloading.

MAPP

An IOU reported that the weakest portion of its transmission system is associated with the transformation capacity from 345 kV and 230 kV to local load areas. Increased transformation capacity is required to adequately serve the local load together with probable contingent parallel flows.

Another IOU reported that the weakest portion of its transmission system is the transformation from its 345 and 230 kV systems to 161 and 69 kV. The respondent also indicated that its principal transmission limitation in the transmission between Minnesota and Wisconsin, which is normally biased heavily eastward. "The limitation in Wisconsin is due primarily to deliveries of power to serve our Wisconsin customers. There's another part of that which is a strong circulation of several hundred MWs from west to east and particularly the overall network."

The municipal joint action agency interviewed from MAPP indicated there to be no physical bottlenecks -- rather institutional bottlenecks, since it depends on 14 different systems to deliver its power.

NPCC

Three IOUs and one state power authority provided information on weaknesses perceived in their transmission systems. The information provided by a fourth IOU was evidently provided in a document attached to the interview transcript, but this document was not made available to the authors of this report.

The state power authority identified several weak links in its transmission system. One of these was also identified by another IOU in NPCC: that being a 115 kV submarine circuit under Lake Champlain, which provides preference power to the state of Vermont. In order to satisfy the regional design criterion of one contingency with no loss of load, this line must be operated at a lower level than is desirable in order to serve as a significant power source for the state of Vermont. This has been the case since the introduction of large generating units in New England and the interconnection with Hydro Quebec.

The state power authority also stated that it is seeking regulatory approval to build a transmission interconnection on the Long Island Sound interconnecting Consolidated Edison's system in Westchester County to the Long Island Lighting Company system on Long Island.

State power authority interconnections with Hydro Quebec were identified as another bottleneck of sorts. Hydro Quebec generation is located far from its load center, and as a result Hydro Quebec does not presently conform to NPCC criteria. As a result, the interconnections with Hydro Quebec are designed to keep the systems separate from one another, either through radial interconnections, generation in isolation, or dc interconnection.

The state power authority is planning to eliminate a bottleneck which exists between Long Island and New York City by building a 345 kV, 600 MW capacity line in the next four years. It is also completing a large line to enhance the system between Utica and New York City. East-West power flows from Niagara to Albany may also be improved by future projects. Finally, the Marcy South line was identified as a project which would relieve a transmission bottleneck.

Two of the IOUs identified the New Hampshire border/North Massachusetts interface as a transmission bottleneck. Transfers of power from Northern New England to Southern New England are impeded at that location by the configuration of the 345 kV network. It was stated that contingencies occurring in New York State or in PJM may constrain the linkage. It was also reported that the completion of the Seabrook line would relieve the constraint to some extent.

One IOU reported that a transmission limitation exists between its Granite and Middlesex substations on its 115 kV system. The anticipated fix is a second circuit parallel to the 115 kV line, built at 230 kV.

SERC

The three IOUs interviewed stated there to be no bottlenecks of significance within their transmission systems. Bottlenecks of minor significance which were identified include the Southern System-Florida interface, which is "quite loaded with contracts"; an area of southeastern Florida, where a separate right-of-way through the Everglades to the Miami area is desirable but not presently cost-effective. An IOU in North Carolina stated that the weakest portion of its system is the 44 kV tertiary lines which are primarily operated radially rather than networked; but that no portion of its system was especially weak.

A federal power authority in SERC stated that its weakest areas include the extreme perimeter of the system, in Mississippi and Kentucky. The system's weakest interfaces are the 161 kV interconnection to Carolina Power and Light from Douglas Hydro Plant to Walters and the interconnection to Louisville Gas and Electric at Summer Shade. The tie to Carolina Power and Light is rated at 335 MVA. The tie to Louisville Gas and Electric is limited to 240 MW because of the terminating 161/115 kV transformers owned by Louisville Gas and Electric.

The weakest internal portion of the federal power authority's system is in northeastern Mississippi, where there is low load density and no local generation. This area is supplied by two 500/161 kV substations and a number of long 161 kV lines with multiple substations serving local load. Voltage drops to large portions of this area may be significant when a 500/161 kV transformer bank is tripped out of service, although uncontrolled cascading is not anticipated.

One of the two cooperatives interviewed currently owns no transmission. The other stated that it is limited to some extent by an interconnection with the South Mississippi Electric Power Association, a 150 MVA transformer that steps down from 230 kV to 115 kV.

SPP

The transcript of the interview of the cooperative in this region was of poor quality. No references to any internal transmission bottlenecks could be discerned.

WSCC

The six IOUs interviewed from the region identified several intrasystem transmission weaknesses. One IOU stated that the transmission lines heading westward from the Four Corners region, in particular a 345 kV line dedicated to Southern California Edison, are significant constraints as a result of loop flow. Generation at Four Corners has been curtailed because of the loop flow loading of these lines. Several other utilities mentioned the Four Corners/westward transmission linkage as a serious intersystem transmission constraint.

A second IOU stated that its transmission overloads are site-specific and mobile, and that they stem from the preponderance of QFs in its service area.

A third IOU stated that its weak transmission link is to be found in a corridor in northeastern Colorado, which is utilized to import low cost generation from southeastern Wyoming. Transmission facilities are being constructed to ease this constraint; however, the interface with Nebraska will become a weak transmission link once the northeastern Colorado constraint is alleviated through construction.

A fourth IOU stated that its access to SPP and points eastward is limited by a 400 MW interconnection with El Paso; but this was less significance because the respondent is not interested in moving power in that direction. In general, the respondent reported there to be no physical transmission bottlenecks internal to its system.

A fifth IOU stated that the south to north transfer capability of its interconnection with Southern California Edison is limited when the San Onofre Station at Saunders is shut down. This is an issue of significance for the respondent because it may constrain the acquisition of additional power from Mexico in the future, and may diminish the benefits of the respondent's participation in the California/Oregon Transmission (COT) Project.

A sixth IOU stated there to be no intrasystem transmission weaknesses of note.

One of the two federal power authorities interviewed from WSCC stated there to be no specific intrasystem transmission weaknesses not being corrected or examined at the time of the interview. The other noted a lack of transmission capacity between the east and west sides of its territory, and also stated that transmission in the west Colorado region is constrained because of loop flow problems.

The state power authority interviewed from WSCC mentioned no specific intrasystem transmission weaknesses.

A municipal joint action agency from WSCC stated that the increasing use of phase shifters in the region forces power onto the few lines which it owns, as well as the lines of other utilities which it uses to transmit its generation to load. This respondent is considering constructing a line to interconnect with Nevada; if it does so, it will put phase shifters on it so that loop flow does not "eat it up." The other cooperative interviewed spoke of no intrasystem transmission weaknesses.

The municipal system interviewed from WSCC referred to the weakness of the northern transmission system of the Intermountain Power Project. The respondent is a partner in the Intermountain Power Project: should "our transmission go down it dumps [our] generation into the eastern part of the western grid, or eastern Utah."
Interview Question #13 asked respondents whether they anticipated any changes to their transmission systems required as a result of parallel flows. Their responses are summarized on a reliability region basis.

ECAR

None of the four respondents with bulk transmission facilities from ECAR stated that inadvertent flows constituted a significant burden. One of the IOUs interviewed responded to the question with a general discussion of the phenomenon; a second expressed the opinion that situations in which inadvertent flows disturb systems not involved in contractual paths of power flow will increase as more economy transactions take place. A third IOU indicated that loop flow is an inherent part of interconnected system operation, and that it is taken into consideration in the normal planning process. A fourth IOU stated that no changes in its system operations are foreseen for the 5-10 year future. This respondent is in the path of parallel flow between New York and Hydro Quebec, but the flow has not been significant enough to cause a problem. However, the respondent indicated that the flow has constrained the sale of power/energy to other systems, in his opinion.

MAIN

One respondent, a joint action agency, owns no transmission facilities, and in this respect the question was not applicable. However, the respondent noted the west to east flow of power from Minnesota to Wisconsin, part of a clockwise loop which extends south to the St. Louis vicinity.

The other respondent, an IOU, stated that loop flow is the potential cause of a problem on cables in Chicago, in which case phase shifting transformers may need to be installed to control the flow.

MAPP

Two IOUs from MAPP responded to the question. One stated that it may need to increase its 345 kV/230kV transformer capacity to adequately service local loads. The second stated that loop flow is a concern, but not a major one; and that the west to east from through Minnesota into Wisconsin is currently accounted for in planning.

The municipal joint action agency interviewed from the region stated that "facilities have to be added because of a bias left to right, top to down." Presumably this statement was uttered in conjunction with reference to a system map. The facilities referred to are transformers of unspecified size.

NPCC

An IOU located in New Hampshire stated that it has rebuilt a transmission line as the result of increased transmission line losses stemming from the completion of Hydro Quebec Phase 1, which interconnects to a 230 kV system running throughout the state. The respondent is connected to that 230 kV system with two 230kV/115 kV transformers, and has a 115 kV grid which virtually parallels the 230 kV system. Increased imports from Hydro Quebec caused increased power flow on the both 230 kV and the 115 kV systems; the conductor size of the latter lines was small, and increased flow resulted in increased transmission losses. "The increased flow increased the losses to the extent that you could justify reconductoring a line just in energy savings." No additional projects are contemplated at this time.

A second IOU indicated that it experiences no parallel flows, but that it is difficult to get power to it, "being at the end" of the regional transmission network. A third IOU in Vermont also indicated that it had not been affected in any way by parallel flows.

An IOU and a state power authority from the region each commented on a current project intended to control parallel flows in the region, the joint construction of a phase angle regulator between NYPP and PJM. Loop flow through PJM occurs when New York imports power from Ontario or even transfers power from western to southeastern New York. As a result, a large phase angle regulation transformer is being installed at the Branchburg-Ramapo pool interface between New Jersey and New York which will allow that flow to be throttled and maintained at agreed upon levels. "The voltage regulation is being designed right now and will be installed to limit those inadvertent flows to less than 400 MW swing either way at the border...[I]t will reduce the inadvertent flows through Ohio and Michigan to manageable levels so in theory it doesn't overload their systems."

SERC

Reference was made in the SERC interviews to several cases of inadvertent flow problems having been solved in the past.

In one instance, the construction of a 500 kV line between two operating companies of the Southern Company System in order to transfer a large block of power (1000-1500 MW) caused serious flow problems in the TVA and Middle South systems. To solve the problem, Southern installed the largest phase shifters in the industry, 1000 MVA, on the 500 kV line. Extremely high loads associated with severe weather has resulted in some instances in altered operating procedures to provide relief on overloaded lines and to maintain reliability.

Within Florida, loop flow occurs from north to south, a situation recognized by all of the state's utilities. It is dealt with in the normal planning process.

Another IOU from the region indicated that it had noticed some loop flow associated with the shutdown of TVA's nuclear units, but that it has caused no adverse effect on the respondent's system.

The two cooperatives interviewed stated that they had experienced no difficulties with loop flows.

SPP

The transcript of the interview with a joint action agency from SPP was not intelligible.

WSCC

Utilities in WSCC provided extensive comments on the loop flow phenomenon. Responses of the region's IOUs are presented, followed by responses of the joint action agencies, federal and state power authorities, and the municipal utility interviewed.

IOU Responses

An IOU located in Arizona experiences seasonally dependent loop flow problems. During low water seasons in the Northwest, it sells energy to California and up into Idaho; while some energy flows north from the Four Corners area (the scheduled path), some flows south into southern Arizona. When this loop flow increases to a certain point, plants located at Four Corners are unable to send their generation westward, and must curtail generation. One of the major problems is the 345 kV line from Four Corners to California which is dedicated to Southern California Edison (which owns 100% of the capacity rights).

This respondent is currently investigating the installation of phase shifters for the Four Corners area. These would block power from coming into the Four Corners area and allow power to flow out. However, there are multiple partners in the Four Corners project, and some of these might be negatively impacted by the phase shifters. It is difficult to get agreement on the installation. The respondent is also considering installation of phase shifters at an unspecified plant in southern Arizona.

Regionally, the respondent would like to see transmission added to move power from Montana/Wyoming into California. Currently loop flow comes down the east side of the regional transmission grid during such transactions, overloading the respondent's lines and limiting its ability to move scheduled energy. The respondent noted that the WSCC has a transmission/loop flow task force "looking at the dispatch of various generation patterns in the whole WSCC area" and at what facilities might be added to rectify loop flow problems.

An IOU from California addressed the topic primarily from a regional viewpoint. It noted that there is a movement to write into the WSCC reliability criteria something addressing the issue of loop flow resulting from new projects; as a result, dc transmission would be more desirable for such projects as the Inland Intertie. The respondent also noted the installation of phase shifters on ac lines, stating that this will increase costs since each new line across the interface would have to have a phase shifter installed on it. In addition, "the problem with phase shifters is that they by and large have not been the most reliable piece of ac equipment..."

In regard to the California-Oregon Transmission Project (COTP), the respondent noted that loop flow has necessitated some changes in planning. In the performance of stability studies to determine maximum line loading capacity, the amount of loop flow must be estimated in order to know how much capacity must be built to provide for scheduled capacity. For the COTP, the respondent estimates there to be 900 MW of north to south loop flow, in the direction of the scheduled capacity. Because some of the other participants in the COTP are located in southern California, the respondent would have to wheel power through its system, where bottlenecks will be encountered. The respondent would need to reinforce its system in order to serve the needs of the other participants. When the cost for upgrading to the scheduled capacity was calculated, the other participants "began to change their mind about how much loop flow they wanted to accommodate or what they would do in loop flow." One alternative considered was to curtail scheduled capacity.

The respondent believes a system of compensation would alleviate the loop flow problem to some degree. It cited the WSCC 1983-1984 Compensation Program, a two year trial at attempting to allocate costs representing the economic losses of impacted utilities to those responsible for the flow. During the first year, utilities documented the amount of curtailment caused by loop flow and the costs involved. Those determined to have caused it would pay directly to the impacted utilities. The program was burdensome to administrate; the compensated parties favored it but the paying parties did not. Eventually the penalized utilities (for the most part, utilities in the

Northwest) pulled out of the agreement. They had suggested that payments be made to a central fund, instead of to the impacted parties, to be used to reinforce the regional system where needed. This did not come about due to differences in what areas needed to be reinforced, who would actually pay, and so forth.

The respondent stated that WSCC is attempting to identify probable future bottlenecks and their magnitude and to ascertain the costs involved in alleviating them versus the costs to be incurred if the bottlenecks remain. WSCC was also trying to establish an operating procedure whereby contributors to loop flow may curtail their schedules when another system is overloaded. Such a procedure may be invoked on an hourly basis, or every few hours. When an overload occurs, the "causer" would we identified, and steps to rectify the situation would be taken. This would entail a big investment in manpower, however, and "people were simply unwilling to make that commitment for that kind of accuracy." So instead, monthly patterns of purchases and sales are being reviewed, and an incremental impedance matrix is being developed to calculate loop flow. The respondent stated that this is a much cruder measurement; if a utility buys and sells in equal amounts the procedure may not capture the loop flow effects that it has caused.

A third IOU from WSCC contended that addition of any major transmission facility in the region will have some impact on loop flow. The "donut", being strongly interconnected and of higher capacity in the western portion of WSCC, can produce dramatic effects upon the weaker, less developed eastern WSCC systems. "The aspects of this create an environment that makes it difficult to add new transmission." Nonetheless, the respondent strongly believes that more transmission is the answer to loop flow problems. Its efforts to model the regional transmission system have indicated that more capacity is needed on the Pacific Intertie, and that a high capacity line extending from the Northwest to the Southwest is desirable.

The respondent believes that control devices installed by some entities are detrimental to WSCC's transfer capability. It notes that utilities pursuing phase shift options are usually constrained from acquiring access to more efficient systems or building new transmission, and are usually located at a "weak link." It recognizes that impacted utilities may employ control devices since they take "less up-front money and allow the utility to utilize its system." If operated properly, phase shifters may be the short-term least cost solution for an individual utility's problems; and, operated properly, may not have a serious impact on the rest of the system. But the respondent is concerned about potential misuse of control devices; if used as a "marketing tool", some utilities could effectively block out whole markets or replace power being transmitted with their own resources. "I have some difficulty having a system with control devices in it that are controlled by one party in the system where they can use those devices to their advantage."

The respondent believes it better to build additional capacity to accommodate loop flow. "Our opinion is that we ought to fix the bottlenecks and build enough transmission to make the system work, and that we all benefit, and that all the customers on the system benefit from that...If ultimately the system's going to need transfer capability, then the logical thing to do is not blow your money on phase shifters, but to go ahead and get on with fixing it."

A fourth IOU, from the eastern portion of WSCC, estimates that 90% of the power generated by utilities in the Northwest for sale to southern California flows down the Pacific Intertie. The other 10% flows east and south through Idaho, Montana, Wyoming, Colorado and down to New Mexico; and the eastern part of the "donut" consists mostly of 115 and 230 kV lines. These circumstances pose two effects upon the respondent and other eastern WSCC utilities.

The most dramatic effect occurs when the Northwest is sending power to southern California and there is an outage or line trip on the Pacific Intertie. Power then flows eastward in such amounts that the 115 and 230 kV lines can not handle the flow. In this event, the respondent sends signals to circuit breakers at the Four Corners area and to an unspecified location in the North. This action effectively breaks the eastern WSCC systems into three "islands" which have been established so that generation and load are matched within each island. This prevents overloading of the lines and frequency/voltage drops which could cause blackouts. It also precludes any intersystem transfers or transactions.

The second effect is related to continuous, endemic line loading. The respondent, in conjunction with neighboring utilities, is strengthening the eastern side of the "donut" by constructing new transmission. Benefits to such constructions include increased interstate power and economy transactions and increased ability to swap generation capacity. However, in strengthening the system line impedance is reduced, so more power flows (including more loop flow). The respondent stated that this increase may amount to only an additional one percent of Northwest-generated power flowing eastward, but that it suffers increased losses on its system as the lines are increasingly loaded. Its ratepayers must cover those losses. In addition, the capacity taken up by loop flow is capacity that may have been used to import cheaper power; economic opportunities may be lost as well. From the respondent's perspective, southern California gains the benefit of cheap hydro power; utilities in the Northwest are able to sell surplus power; and the utilities on the eastern side of the "donut" shoulder the losses.

The respondent believes a single-ownership approach may be the only way to make the southern California utilities pay for the benefits accruing to them. Although the WSCC experiment concerning loop flow compensation was a partial success, the process was too unwieldy and complex: one had to verify that the line was overloaded, how much generation was backed off, what the cost to ratepayers was, and that the overloading was indeed due to loop flow. The respondent also believes that some of the blame for the ultimate failure of the experiment rests with West Coast regulators, who it speculates may not have approved of paying money to other utilities without tangible purchases. The West Coast utilities have formed the Western Systems Power Pool, which would act as a proxy for single-ownership. However, they have not yet come up with a plan to redistribute the benefits.

A fifth IOU, located in the southwestern portion of WSCC, stated that it is difficult to remain in an "accommodation" mindset regarding loop flow in the face of its impact on the respondent's system. Loop flow is one of the primary drivers of new transmission planning in the Four Corners area westward, primarily because loop flow restricts the ability of southwestern utilities to market their power in southern California. The eastern and southwestern portions of the WSCC "donut" were planned only to handle associated generation resources; at certain times, loop flow approaching 800 MW requires the curtailment of generation schedules for the respondent and its Four Corners partners.

This forced curtailment amounts to a reallocation of resources, in that the amount of power flowing through the lines is the same, but someone else gains at the respondent's expense. The respondent also noted that the requirement to overbuild a transmission line to accommodate loop flow in addition to schedules transmission presents a problem in that the added cost is divided among multiple partners in a line, who may be receiving entirely different benefits from the line to begin with.

The respondent stated that the WSCC loop flow compensation experiment failed primarily because of problems in identifying contributing violators and those entities violated. Participants were unable to agree on the redistribution of the historical benefits which the western side has received, versus the costs the eastern side of the "donut" had always accepted. After so many years of operating under these conditions, it is difficult according to the respondent to get the western utilities to realize the impact of loop flow on those elsewhere in WSCC. WSCC does not have policing arrangements; it only coordinates. "The pursuit of economics of delivery of Pacific Northwest resources into the California market has caused and is causing increasing economic hardship to the Desert Southwest utilities."

Another contributor to loop flow, according to the respondent, is the Pacific Intertie ac lines themselves. Although unlikely that both lines would be unavailable at the same time, this has occurred. When the two 500 kV ac lines are down, the dc line can't absorb the excess power, which then flows eastward and then through the Southwest. To counteract the massive flows produced, there is a transfer trip scheme in place. When the lines are down, the Northwest has the generation and goes "over-frequency"; southern California has the load and goes "under-frequency." Depending on the extent of the outage and the flows, the respondent may experience under-frequency load-shedding. With additional lines and capacity being considered in the western WSCC (such as the California-Oregon Transmission Project), the northwestern utilities are still relying on the transfer trip scheme; but without changing the current "defense", the southwestern utilities could be impacted even more.

The respondent noted that the utilization of phase shifters is increasing in the WSCC. When someone blocks loop flow with phase shifters, those utilities receiving the flow must curtail generation and transmission schedules. WAPA is installing phase shifters on its own lines because of estimated losses of from three to nine million dollars a year. This may provide the respondent with the opportunity to market both economy and bulk energy if the flow is blocked above Colorado.

The sixth IOU from WSCC stated that it is affected by loop flow, but not significantly since it is located at the southwestern corner of the loop. However, it recognizes its effect upon others. "The transmission planners that I know that have been in the business five years cannot believe the levels of loading that we're putting on systems now compared to five years ago." For this reason, the respondent believes that "Southern California Edison is probably in one of the worst positions on the loop in terms of impact because of the impacts on some of their heavily loaded lines."

In regard to the demise of the WSCC loop flow compensation experiment, the respondent noted "it becomes almost impossible for everybody to sit down at a table and agree that here's the inadvertent flows, here's why they're going there, here's the person who caused it, because you can always find a different way to run that load flow to come up with different results." Plans to allocate costs based on actual flows depend on the assumptions made and "everybody's planners know which set [of assumptions] makes the other party guilty of inadvertent flow...If you make a slightly different assumption at the level of what this generator over here on somebody's system is running, you're going to get a different set of flows."

The respondent does not believe pricing inadvertent flows would alleviate problems at Four Corners or Bonneville because it would not generate enough capital. It is easier to build and install phase shifters than to develop an equitable pricing system, even though the respondent acknowledges that phase shifters may impact negatively on other systems.

Joint Action Agency Responses

One respondent is a municipal joint action agency located on the weaker eastern portion of the "donut." It is strongly affected by loop flow via Utah Power and Light. UPL wheels power to the respondent's member municipals. The respondent is beginning to build its own lines, and is concerned over the way loop flow is currently addressed.

The respondent cited a specific case, the 230 kV line built by Salt River Project and WAPA to bring power down from the Craig Project to the Phoenix area. This line has become a significant bottleneck because of loop flow. It is the only line through southern Utah and is interconnected with several entities which must curtail generation when loop flow is manifested to prevent overloading the lines. WAPA is building an additional 345 kV line in western Colorado and would like to upgrade the 230 kV line mentioned above. While ordinarily this would alleviate the loop flow problem, WAPA is considering installing phase shifters on both lines, thereby pushing flow onto the respondent's lines and affecting UPL's ability to wheel to the respondent's customers.

The respondent believes the installation of phase shifters will cause greater losses to be incurred, not only by themselves but for those systems which do not have them. The respondent has no phase shifters currently, but is considering placing them on a 230 kV lines proposed to interconnect with Nevada.

Another harmful method in practice of stopping loop flow is the opening of switches. "We were watching Southern California Edison down here disconnect switching to stop the loop flow. That just plays havoc on our systems up here."

A second respondent is located in Utah near the eastern portion of the WSCC system. Loop flow has diminished in its system as a result of improvements to other systems in the area. However, north to south flow in Colorado which moves westward into Utah, then south to Arizona does impact upon the respondent's system. A proposed 345 kV line should help to alleviate this situation.

No major changes to the respondent's system are planned as a result of loop flow. "Western Area Power Administration purchased phase shifters for southern Colorado and they're going to block or eliminate loop flow around the eastern side of the [WSCC] system...We feel that they're very concerned about the operation of those phase shifters and how they affect us." Theoretically, WAPA could block the loop flow and turn it westward onto the respondent's system; while the respondent believes it will pick up some loop flow, it also believes that WAPA will take their situation into account. On the other hand, "I suppose if it did become an extreme problem we might have to install phase shifters. The same old story. You put them in one place, you have to put them on the neighbors."

Another option in the event of an extreme loop flow problem is upgrading transmission links to a higher capacity, but this would require that a number of partners in the enterprise be assembled. Financial considerations might eliminate this option: the respondent noted that its belief that firm contracts for sales of power are necessary to justify expenditures on new construction. "You don't build transmission just because there's a lot of loop flow on, and maybe you can make a bunch of non-firm sales to get your cost recovery."

Federal and State Power Authorities

Two federal power authorities in WSCC were interviewed. One is affected by loop flow in the Spring and early Summer when there is heavy runoff in the rivers of the Northwest. During such seasons the respondent has excess generation which it markets to California, loading its ac interties to full capacity. Under these conditions loop flow is counter-clockwise, and is caused by the massive energy flows to southern California and the Southwest. The flow swings onto the respondent's grid, lowering the capacity of its lines for schedules sales to California. In other seasons the flow is clockwise and limits Arizona Public Service's ability to market power in California.

The respondent is not planning construction of any transmission lines to offset the impact of loop flow. It noted that a dc transmission line would alleviate some of its marketing problems, and it is "discussing" the possibilities of dc transmission. "Big phase shifters" were also noted as a possible technical solution, but some utilities would be adversely affected by their installation. The WSCC compensation experiment was also mentioned as an administrative solution.

A second federal power authority has been experiencing loop flow problems since the early 1960s. The amount of loop flow experienced depends upon the conditions in the Northwest, the time of day, season, and what is moving on the system. Usually the flow is clockwise, and the respondent's system is "blocked". If the flow switches to a counterclockwise pattern, the system is relieved of loop flow. Loop flow adversely affects the respondent's ability to market power or to wheel to other entities.

Loop flow has had such a serious effect on the respondent's operations that it is installing phase shifters on a 345 kV line under construction in western Colorado. These phase shifters are to be placed in 345 kV, 300 MVA pairs at two locations. The cost of the four units is $12,000,000, not including installation costs.

The respondent has assembled a report on the effects of phase shifter installation on WSCC members. It noted that other entities have already installed eight phase shifters, all unidirectional, 60 degree deflectors. These permit power to move out of an area but prevent it from moving in. The respondent's phase shifters will have 60 degree bidirectional capability. The respondent acknowledged that some entities will suffer losses as loop flow is pushed on to their systems, but the installation of the phase shifters will greatly reduce the respondent's losses. The respondent suggested that dc transmission might be the answer to WSCC loop flow problems, but it claimed there to be disadvantages (these were unspecified).

The state power authority from WSCC stated that any changes that may be required in the transmission system as a result of loop flow are unknown at this time.

Municipal Systems

A municipal system in southern California suggested that loop flow problems result from the practices of the utilities on the eastern side of the "donut." The western side has strong, high capacity lines, and the eastern side is composed of lower voltage, lower capacity lines; "so when they try to schedule energy up or down the east side of the loop, it instead flows over onto our lines." The respondent also stated that ..."we feel there has been abuse of overscheduling by many utilities on the east side of the donut." The respondent experiences loop flow when there is little surplus power in the Northwest, and economy purchases and sales move loop flow in a clockwise pattern. It also experiences loop flow when there is the loss of a major transmission element on the western side of the "donut".

Interview Question #14 asked respondents to identify portions of the regional transmission system outside their own service areas which they wished were strengthened. It also asked whether the respondents would be willing to participate in such ventures, and under what conditions; and whether regulatory barriers would impede their participation. Answers responsive to this question were in some instances provided to Interview Question #12; if such responses clearly pertained to the regional transmission system beyond a respondent's service area, they have been summarized below.

ECAR

Two IOUs in ECAR stated that they wished the transmission system to the East, including PJM and the New York area, was strengthened. One of the IOUs indicated that they would not participate in such a project unless it provided a transmission route for the sale of power to Pennsylvania, or to New York state. The respondent noted that in the latter case, the power would have to be transmitted through PJM, which likely would want to buy all that is available. The other IOU stated that sales opportunities would also motivate its participation, but that it was uncertain whether Ohio regulators would allow return on such an investment through rate base treatment.

Another IOU stated that its contracted sale of 650 MW to GPU had been constrained by transmission limitations near GPU.

The other IOU interviewed from the region cited no particular weaknesses in the regional transmission system. It suggested that its participation in such a project "for just a contribution to general reliability" would "hopefully" be precluded by its regulators.

The municipal joint action agency/power broker interviewed from ECAR stated that it would like to see the transmission system in southwestern Ohio, and particularly the Ohio Edison/Dayton Power and Light interconnection strengthened; but that it lacks legislative authority to pursue joint projects.

MAIN

The IOU from MAIN stated that the west to east transmission path from Minnesota through Wisconsin could be strengthened, although opportunities for power transactions over the path would not presently justify its participation. MAIN characterizes the transfer capability of the transmission path to be "marginally adequate" at present.

The joint action agency from MAIN stated that it would like to have the west to east transmission path from Minnesota through Wisconsin strengthened, including the west to east Wisconsin transfer capability. In addition, it stated that its transactions and ownership options are severely limited by "the Northern States blockage." The respondent stated that the state's private suppliers continue to deny its requests to buy into existing and new transmission facilities "on a reasonable basis."

MAPP

One of the IOUs interviewed stated that there were portions of the regional transmission system external to its service area that it would like to have strengthened, but it identified none specifically. It stated that any regulatory problems faced in such an endeavor would not be insurmountable. The other IOU from MAPP stated that it was not aware of any weaknesses in particular; transmission weaknesses were "generally identified and fixed by the pooling people." Hypothetically, if benefits to the company were to be derived, it would participate. However, "there may be some problems in physically constructing and owning some systems outside of your own jurisdictions, particularly in other states: we're not allowed to operate interstate." The respondent suggested that one could "get the other utility to build it, get some arrangements to pay for a share."
The municipal joint action agency in MAIN stated that it would participate in the Prairie Island to EauClaire line, if it could be assured of a payback, through power rates for example. It would be subject only to state siting regulations.

NPCC

An IOU interviewed stated that it would like the 345 kV system from the Niagara Falls area to Rochester and Syracuse strengthened; the transmission path comprises a major part of the path from Ontario Hydro and the Niagara project into the central part of the state. When purchases from Ontario Hydro are heavy, voltage sags occur on the 345 kV system in the Rochester area. The same respondent also indicated that transmission in the Vermont area could be strengthened. It indicated that there had once been planned a 345 kV transmission line from the Essex area in northern Vermont south to Rutland, which could have provided a path for its purchase of power from Hydro Quebec to a point not too far from the New York border. In either case, the respondent would be willing to participate financially in a project if economic benefits to it were clearly demonstrated. The respondent was uncertain of how regulators in New York or Vermont would view such participation; however, "New York State Electric and Gas has had an experience in building the Homer City Plant in Pennsylvania and the transmission connecting that plant into New York, that suggests favorable consideration as long as the risk is minimal and a favorable cost-benefit performance is expected."

Another IOU noted that its imports of power from Hydro Quebec present potential contingency problems for utilities in New York. The contingencies experienced in New York would be voltage limitations, and it was speculated that some kind of static source in the New York area might provide for increased imports for the respondent and preclude voltage limitations in New York. Studies to determine whether this is so were underway at the time of the interview.

Another IOU in New England made the same point: "To the extent New England transactions with Hydro Quebec are limited by contingencies occurring in New York and PJM, [there] may need [be] some involvement in correcting those problems. This respondent also stated its wish that transmission were strengthened to provide for the movement of power from northern to southern New England, but that economies for the Scobie-Tewksbury line, which would facilitate such movement, "aren't there yet."

The other IOU from NPCC suggested that the transmission system of Public Service of New Hampshire near Littleton, New Hampshire could be strengthened, as could a portion of the system of the New York Power Authority near Plattsburg, New York. It would be willing to participate financially in either project subject to constraints of its state regulatory board.

The state authority stated that it "is not looking for a lot of long-term strategic transmission regional interconnection projects at $500 million a throw and multi-state licensing.... We believe the regulatory environment discourages... [projects strictly for reliability reasons or future capacity requirements] so much that until there are instances of service reductions or foregone economic development opportunities where the public understands that and changes behavior of whatever regulatory agency...that there is no incentive whatsoever for a capital intensive owner to make the investment."

SERC

Neither the three IOUs interviewed nor the state coordinating group stated there to be any particular weakness in the regional transmission system. One of the IOUs stated hypothetically that it would participate in such a project, depending upon the economic benefits. No particular regulatory problems were foreseen, except the potential impact of the new tax law, which may treat contribution in aid of construction as an operating revenue which is taxed, as opposed to a capitalized investment. Another stated, "I don't think we would be in the position of being willing to take a financial interest in XYZ Company's transmission system just to relieve a bottleneck that might not have any financial implications for us other than reliability."

The federal power authority stated that it participates in projects to strengthen the regional transmission system when it is determined to be of mutual benefit. No regulatory barriers to such participation were noted.

Of the two cooperatives interviewed, one stated that it was aware of no regional transmission system weaknesses, but that it would participate in mutually beneficial joint projects and would not face regulatory constraints. The other stated that it would like to see strengthened the interconnection between Big Rivers Cooperative and AEP, as well as the transmission path for Ohio River basin power to flow to the Southeast. In regard to the latter, the respondent identified a 138 kV line connecting TVA and Carolina Power and Light as the only line connecting the systems. It would be willing to pay its pro rata share in such a project, and would be subject to no regulatory constraints.

SPP

The joint action agency from SPP stated that it would like the regional transmission system strengthen "so Kansas City can interchange more power from Minneapolis, if it would benefit us."

WSCC

One of the IOUs identified four major intersystem bottlenecks. One is to its northwest: lines currently rated at 2500 MW and being upgraded to 2800 MW are used by the respondent to import hydro power and economy energy. An additional 1600 MW transmission capacity is to be built in the near future. To the respondent's south, light loading conditions can cause stability problems and result in the loss of one of three 500 kV lines. Under steady state conditions the lines can overload, depending upon the level of generation at the southern end of the system and the level of load. The respondent has established operating levels depending on whether the load is peak or non-peak and on the number of units operating at Diablo Canyon. The respondent also noted a bottleneck between itself and Sierra Pacific near Reno, comprised of two 115 kV lines and one 60 kV line.

Finally, the respondent remarked on limitations of the California/Arizona intertie. Without providing specifics, it noted there to be thermal limitations. In addition, it noted that when certain levels of power are transferred simultaneously from the Northwest into California and from Arizona into California, the lines trip and cause a cascading outage of all ties between California and Arizona, causing an "islanding" effect.

The same respondent noted in regard to potential regulatory barriers to spending money on a project outside one's own service territory, that such a proposal would be judged by California regulators on its own merits.

A second IOU from WSCC articulated the need for additional North-South capacity on the Pacific Intertie. It was stated that this need may be partially addressed by the construction of of a third Pacific Intertie line or by the California-Oregon Transmission Project (COTP). This respondent is a participant in the Inland Intertie Study, and stated in regard to the Inland Intertie that it "would be separate from the BPA [Bonneville Power Administration] area and other utilities then would have more opportunity to participate in the business." This remark was made in conjunction with the observation that BPA is required by federal regulation to wholly own and control certain transmission lines in its area.

This respondent has run a limited number of studies on the eastern and southeastern areas of the WSCC, the weaker portion of the "donut", in the course of WSCC loop flow studies. It indicated that these studies support the location of new transmission currently under construction in that area. The studies also indicate that fixing bottlenecks is in general a better solution to loop flow problems than is an system "artificially constrained" by regulation or physical devices; and it would be willing to participate in such "fixes."

The issue of phase shifter installation to combat loop flow is a source of concern for this respondent: "We have a substantial concern that parties that are currently impacted that are at the bottlenecks will install, and operate improperly, control devices." Even if operated correctly, the installation of such devices is only a temporary solution: "If ultimately the system's going to need transfer capability, then the logical thing to do is not blow your money on phase shifters, but to go ahead and get on with fixing it. Not everybody shares that philosophy." The respondent expressed a concern that such control devices could be used as "marketing tools" which would be used only to the advantage of the owners; forcing everyone to install phase shifters, with consequent constraint of the system and a decrease in transfer capability.

This respondent, which operates in several states, suggested that investment in a transmission facility outside its service area would probably not encounter regulatory roadblocks if it could be shown that obtaining access to transmission elsewhere improves the company's ability to get its generation to market.

A third IOU identified two weaknesses in the regional transmission system. The first is the Four Corners westward transmission path, which is heavily loaded and provides no opportunities for securing additional firm capacity. The second is the transmission path northward, which is insufficient for the respondent to take further advantage of relatively inexpensive hydro power.

In regard to potential regulatory roadblocks to participation in a transmission project outside its service area, this respondent expressed that it might encounter such roadblocks.

A fourth IOU referenced the loop flow problems in the West and stated that it would be willing to participate in projects to alleviate loop flow, if it would benefit economically from such participation. "We would not know where our Commission's view would be of us putting dollars in some other state." –

A fifth IOU located in Colorado cited the existence of bottlenecks between Colorado and Nebraska. The bottleneck could be alleviated with the construction of facilities in Nebraska, which would require the establishment of a corporate entity in Nebraska. This entity would be involved with Nebraska regulatory bodies.

A sixth IOU stated that it would be willing to participate financially in increasing transmission capacity elsewhere so that it could market its excess power, but that it faces regulatory barriers. "We have no incentive to participate since we can only recover costs...FERC has considered and has allowed some incremental costing approaches. But there's ambiguity in the consistency of that application."

One of the two federal power authorities interviewed identified an area in Idaho and Western Montana where, during certain times of the year, it attempts to obtain hydro and coal-based generation. The respondent has experienced problems in getting all the potential generation out into the system; the grid is still being developed. This respondent also desires to expand its capacity in the ac and dc lines of the Pacific Intertie. Currently, it is unable to export all its surplus hydro power southward. By 1989, the respondent intends to increase the capacity of the dc line by 1000 MW by adding converter capacity at each end, and is looking to increase the ac line by 1600 MW from the Oregon border south.

The other federal power authority stated that it "would be more than willing to look at participating in [additional transmission facilities]...if it's something that would help out the loop flow situation.

One of the two cooperatives interviewed cited the 230 kV line from the Craig Project to the Salt River Project systems as a transmission bottleneck. This line is the only line interconnecting through south Utah, and it is heavily loaded because of loop flow. Consequently, utilities in the region are required to curtail their generation schedules to prevent thermal overloading of the line. This respondent also noted Western Area Power Administration's potential plans to install phase shifters on a 345 kV and a 230 kV line in western Colorado, which would channel additional loop flow through Utah.

This respondent noted several roadblocks to its participation in strengthening such ties. "One is the certificate of conveniences and necessity in different states. Every state seems to have a different rule on how that goes through and that needs to be coordinated. From the municipal's point of view...the new tax law can put a real cramp on what could be going here. The main thing, though, is that regional planning really does need to come through...there are 27 utilities involved in the Inland Intertie.

The other cooperative cited a bottleneck in southern Colorado which increases the loop flow effects felt by the respondent. The construction of a planned 345 kV link from Colorado to Arizona/New Mexico should alleviate this situation. The respondent also noted that it would wish to strengthen its rights to transmission throughout Utah into other areas. "We would buy in, and take an undivided interest, if that was the route to go, or a divided interest with some rights of block and pay our share, but we have not been able to do that [because of the opposition of Utah Power and Light]...I would not say we've had any regulatory barriers to that.

The state power authority interviewed stated that it would like to see portions of the regional transmission system between the Pacific Northwest and California, the Pacific Northwest and Souther Nevada/Arizona, and Colorado to Arizona strengthened. It would consider participating financially if it were determined to be economically feasible.

The municipal utility from WSCC cited the ac lines of the Pacific Intertie as a weak link in the regional transmission system. It also noted the weakness of the transmission system in the eastern part of WSCC, primarily the lines in Utah, Colorado, and Nevada and the northern connections to Wyoming and Idaho. If there is an outage of lines in the West (particularly the Pacific Intertie), generation in the Northwest flows eastward; the lines, unable to handle the power, trip breakers and may cause blackouts. It also stated that its market with Canada is somewhat blocked because of the intertie access policy of Bonneville Power Administration.

Regarding its participation in projects to strengthen such ties, the respondent stated that it had been approached and would be interested in participating in a project that would reach to Canada, come down the east side of WSCC (tieing in at the Intermountain Power Project) and then come into Southern California. It foresees no regulatory barriers as far as financial participation is concerned.

Interview Question #20 asked respondents whether they face any physical or regulatory barriers to increased purchase or sale of energy or capacity. The responses summarized below also include references to institutional barriers to purchase or sale of energy or capacity. Responses are organized by reliability council region.

ECAR

One of the four IOUs from ECAR stated there to be no regulatory barriers to its energy or capacity transactions. Insufficient transmission capacity to the east prevent increased sales to PJM and New York State.

A second IOU stated that the acquisition of ROW is its primary regulatory barrier. It also referred to the lack of transmission capacity through Pennsylvania, which constrains its potential sales of energy or capacity to GPU. Finally, the respondent noted that its ability to obtain power from Ontario has been constrained by difficulties associated with the completion of transmission facilities associated with the Bruce nuclear facility in Canada.

A third IOU specified no particular physical barriers, apart from transmission capacity in general. The respondent operates in Kentucky, and did note two regulatory barriers to its increased sale of purchase of energy/capacity. The first of these results from regulatory rules involving the fuel adjustment clause pass-through of costs associated with demand and energy purchases. While the fuel adjustment clause permits the pass-through of energy charges, the demand portion of short-term transactions must be recovered in rate cases in Kentucky. Thus, in a situation in which the total cost of a short-term transaction with both demand and energy charges is less than that of an economy transaction with only energy charges, the utility would prefer to minimize total cost by entering into the short-term transaction but for the regulatory requirements governing cost recovery. The second regulatory barrier involves the potential treatment of a utility with surplus capacity, which would prefer to make off-system sales of its surplus at rates which do not totally recover wholesale demand charges to not utilizing that surplus at all. The respondent pointed out that its own wholesale customers may under such circumstances complain that off-system purchasers of wholesale power are being offered rates lower than those offered to system customers, despite the fact that any off-system sales will be to the benefit of those customers on-system.

A third IOU noted no regulatory problems, but also cited the lack of transmission capacity to the east which prevents its off-system sale to PJM and New York.

The municipal joint action agency/power broker from ECAR stated there to be various institutional barriers to its operations.

The respondent has asked Cincinnati Gas and Electric on several occasions to allow wheeling in, out and through its transmission area on behalf of its members. "To date, CG&E is the only IOU in the state with whom we don't have some form of direct, or indirect, transmission arrangement. To date, CG&E has elected not to allow..[us]..to do other than utilize existing two-party buy-sell interconnection arrangements. CG&E won't respond directly to our requests, so the other interconnected utility, such as Dayton Power and Light, has to make such requests of CG&E. We'll send CG&E all appropriate schedules, but CG&E will only cooperate DP&L makes the request. And, that's only operable through interconnection or partial-requirements arrangements that we or our members might have with the local or neighboring utilities."

The respondent noted other restrictions associated with two-party buy-sell transactions. "AEP has interpreted [our 1974 agreement] such that they'll only let us use the two-party buy-sell transactions under certain conditions. If we want to take title to the power, the only way we can do so is with a 12-month or more transmission capacity reservation from point A to point B. If we want to go from point B to point A, we must incur another 12-month transmission capacity reservation. AEP will not let us buy-sell from one community to another....For example, if CIPS, a summer peaker, has winter seasonal power available to sell us for three months of the year, which would compliment our Buckeye seasonal power purchases, we must pay for a one-way 12-month transmission capacity reservation through AEP for a minimum of one year, a significant disincentive to complete the transaction." In regard to the same interconnection agreement, the respondent stated that AEP has "recently further, at least in conversation, defined such interconnection criteria which has the potential to further hinder interconnections. This is because 1) AEP would be interpreting this on a one-to-one basis for each...member community, as opposed to the group as a whole, and 2) various reserved capacity requirements, etc. are now being applied numerically, which did not exist as such in the original agreement."

Another problem with series of two-party buy-sell transactions is that "the transaction is technically less firm with title to the power taken by all the utilities in the path. If one of these utilities has a problem and the power happens to be going through their system at the time, the utility doesn't necessarily have to sell it to the next utility down the line."

The respondent also stated that several of its member municipalities have had to construct transmission lines to IOU systems beyond the local IOU because of restricted transmission access to desired sources of generation. In addition, it stated that some of its potential transactions have been limited by IOU pre-emption of interconnection capacity. "DP&L has taken the position that if they wish to use that interconnection to sell power to Toledo Edison, for example, when we might be using the interconnection to transmit third-party power through DP&L on a prearranged basis, they have the right to interrupt us with no notice. This is a short-term transaction, true, but no notice to be given so that a DP&L sale of generation and transmission capacity can be made through that same interconnection point in order to make more money when we've prearranged for other deliveries greatly concerns us."

MAIN

The IOU from MAIN stated that state regulatory attitudes would prevent the building of a Manitoba-to-Chicago tie "just on low-cost energy": the states through which such a line would pass would not be directly benefited, and their regulatory authorities would not approve.

The municipal joint action agency from MAIN commented on several barriers to its increased purchases of capacity or energy. First, it stated that the IOUs with which it is interconnected would not allow it to buy pro rata shares of transmission capacity at reasonable rates. Wisconsin law will not allow it to construct parallel transmission paths because of anti-duplication statutes. The respondent stated that Northern States Power's claims of insufficient transmission capacity for imports from Minnesota eastward into Wisconsin. "We question whether this is truly a physical barrier or just not in the interests of the owner to make transmission capacity available. Their calculations of available capacity include their possible non-firm transactions to the detriment of our firm transactions."

The respondent also noted as barriers the west to east loop flow condition existing from Minnesota into Wisconsin, and "the potential to use the transmission bottleneck to leverage coordination services, sales, and make decisions on the basis of retaining market power....If you are in the middle of a service area as a muni and the supplier utility offers power for 42 mils including the transmission rate, and you want to go to partial requirement service and piece together some things, they can price it in such a way that you just cannot do it. They can say you have to buy their backup or their reserves to meet the conversion requirements."

MAPP

One of the IOUs in MAPP stated simply that transmission facilities in some areas are technical barriers to increased sales or purchases. The other IOU stated that "there are some transmission facilities on a 345 kV line south of our system...I think, in general, physical facility barriers are minimal and regulatory barriers do exist. The latter were not specified.

The municipal joint action agency from MAPP stated that it has experienced difficulties in negotiating the right to wheel power across interconnected systems. For example, "there's also opportunity to market our power west. We think we can get across the east/west separation but once we get across it, then its difficult to move it to whomever we conceivably want to sell it to. The real reason is that we would be displacing some of their power. People don't every say to us, no, you absolutely can not but, for example, we've been trying to sell to different people and we hear every once in a while from a utility that they've been into this community and told them,...[the respondent] gave you an offer, did you know that you have to pay for regulation service to use, you have to pay us for dispatch services, you have to pay use for reserves, you have to pay us for backup. And in one instance, the stretch to be wheeled was maybe 100 miles and it was 15 mils it all added up to, and most of it in our minds was hokey stuff that the uninformed would probably believe and not consider us anymore."

The respondent also noted that the Wisconsin Commission's denial of construction of a 345 kV line from Prairie Island to EauClaire, Wisconsin on the basis that it did not benefit Wisconsin had affected a "critical area for flows...We really need lines across Wisconsin."

Finally, the respondent also noted that its dependence on 14 different systems to deliver its power. "Occasionally we run into this problem, if we want to sell to somebody over there that is away from where we historically intended to sell. Then we...may be constrained from delivering."

NPCC

One of the three IOUs from NPCC is a member of NEPOOL. "Undoubtably there could be ways to create better market conditions for purchases and sales of power between utilities within the pool. But I don't think that's been a big problem as far as we're concerned. We found ways to...exchange capacity and improve individual company mixes within the frame of the NEPOOL Agreement. Now outside of the pool, clearly we're limited by the tie-interconnections that we have....There are times when I would like to have been able to make purchases from ONtario, Pennsylvania, and I couldn't get transmission access across New York."

Another of the IOUs stated that increased purchases are limited in certain circumstances by interconnection capability. Two areas of the regional transmission system could be strengthened in the respondent's opinion: the 345 kV system from Niagara Falls through Rochester to Syracuse, and in Vermont where a 345 kV line from Essex to Rutland, once planned, has not been built.

A third IOU stated that its physical barriers are limitations in interconnections to NEPOOL and NYPP. A fourth IOU stated that it was not aware of any particular barriers, either physical or regulatory, to increased sales or purchases.

A state power authority from NPCC was also interviewed. Although it mentioned two physical bottlenecks of consequence, a weak interconnection with the state of Vermont and with Long Island, each of these is being relieved with projects already underway. The respondent also mentioned that, since Hydro Quebec is not presently in conformance with all the criteria established by NPCC, its interconnections are either radial or dc in order to keep the systems separate from one another.

The state power authority also spoke of the disincentives to invest in new capacity which the present regulatory system maintains. "Whether it's a nonprofit entity like ours or it's an IOU, I don't know anyone in the country who is willing to undertake the right long-term project anymore, because they're afraid they'll be denied the cash so long that they'll be in financial trouble...we would be very disinclined to undertake any project which had a negative cash flow after five years in operation. Frankly, there's a lot of them these days....We will not do a project strictly for reliability reasons or strictly for future capacity requirements. We believe the regulatory environment discourages that so much that until there are instance of service reductions or foregone economic development opportunities where the public understands that and changes behavior of whatever regulatory agency,...that there is no incentive whatsoever for a capital intensive owner to make the investment."

SERC

One of the IOUs stated that TVA is constrained under the Self-Financing Act of 1959 from selling power outside its service area of June 1, 1957 or doing business with utilities beyond those with which it had interchange agreements on July 1, 1957. It also was uncertain whether transmission facilities could be built in Mississippi to serve external sources, given state regulatory treatment.

A second IOU stated that no regulatory barriers would hinder its aid in construction of facilities in other states, if the respondent's customers would benefit from the construction. Other comments concerning regulatory roadblocks concerned the policies of FERC. First, it was stated that the FERC should not review individual components of a contract without giving consideration to the entire set of terms, conditions and prices of the contract. "This is a situation...where we had some transactions with other utilities for wheeling services -- which were bilateral, negotiated contracts -- and in the filing process at the FERC, they basically looked at a section of those contracts and wanted us to file certain things as tariffs. In other words, even though a transaction which may have lent itself to some efficiency was being proposed to them, the fact is that under their authority, once a document or a rate is filed and accepted they have some purview and jurisdiction over that rate, and may deem or seek some modifications to that rate." Second, the respondent stated that it would like to see FERC permit transactions which are less than split-the-savings, "in other words more benefits to the purchaser and less to the seller, take place without having to have a specific filing to justify that rate. We say that FERC should permit deviation from split-the-savings pricing policies for emergencies and basically set out a per-determined list as to when you can deviate from split-the-savings." Finally, the respondent stated that FERC should establish clear guidelines to calculate incremental and decremental costs to utilities.

The third IOU from SERC noted that it would be hindered from providing transmission access to its system through the Carolinas if the system's customers were to receive no benefit from the project. From a technical perspective, the respondent stated there to be no particular bottlenecks, other than a number of 500/235 kV autotransformers on its system which could limit the ability to import power.

The bottlenecks cited by the two joint action agencies from SERC were institutional in nature. One respondent noted that "it takes us years to negotiate contracts to permit selling or coordination of spot power purchases." Other restrictions associated with contractual arrangements with IOUs include "the Duke Power arrangement, they insisted on complete ownership of the transmission. They will permit us to bring in outside resources, up to our load growth, without notice. Anything larger than our load growth will take eight years notice for us to bring in." Yet another negotiated constraint: "In 1976 CP&L was not willing to set a system-wide wheeling rate. They said, 'you bring us the quantities of power that you want wheeled, when you want them, and so forth, and we'll tell you what the price is.' That makes it almost impossible for you to negotiate a deal, if you don't know what the wheeling cost is going to be."

A second joint action agency stated that "the IOUs have been very reluctant to work with a G&T cooperative, either on transmission planning or generation planning." The respondent also stated that TVA required in a proposed ten year wheeling agreement that it be able to terminate wheeling by giving a three year notice. This was unacceptable to the respondent, and no wheeling agreement was reached.

The federal power authority noted the constraints to its sale of power under terms of the Self-Financing Act of 1957, described above.

SPP

The only roadblock to increased sales or purchases of power noted by the joint action agency from SPP was that "it's much more difficult today to build lines for fuel cost differences for energy transfers unless you have got some long term commitment on the energy. You can get short term commitments, [but] by the time their load is developing they want that capacity for themselves."

WSCC

One IOU stated there two be two areas of concern relative to regulatory roadblocks to increased sales or purchases of energy or capacity. The first of is the fact that non-regulated competitors do not have to obtain approval from FERC to make coordination type sales, and regulated entities do. "In effect you can say in [a rapidly changing market]...we lose sales because we have to go through a regulatory process when some of our major competitors don't." The second concern expressed was that FERC standards require of regulated entities that all transmission transactions be cost based, thereby conferring on unregulated utilities an advantage.

The respondent also stated that it has had problems in coming to terms with the Navaho nation on a proposed additional transmission line out of the Four Corners area to the West.

A second IOU stated that "we have no regulatory barriers and the physical barriers we are solving by building transmission." However, several other impediments to increases sales or purchases of energy and capacity were identified. One impediment is the fact that the Western Area Power Administration maintains by law ownership over specific portions of the transmission system in the West, which it sometimes uses for its own economic benefit first. "That's understandable but that doesn't always work out best for the region. There have been times when the federal government has been very difficult to deal with." Another impediment cited was the impact of loop flow. "When the power flows around through Colorado that causes losses on our system due to the power that's scheduled from the Northwest down to California. The Colorado ratepayers have to provide the generation, both the capacity and the energy, to supply those losses on the Colorado system, they have to supply the transmission capacity and that means that's capacity that they can't use to go get cheap power of their own because it is being used to transmit the power of others. So they are picking up the costs of something that is accruing to the benefit of the California and the Pacific Northwest ratepayers." Another impediment identified was the "typical mentality of the utilities, regulators and the financial communities...that if you're going to put your money into something like a transmission line, you've got to show that you're going to transmit firm power over that line in order to justify it over a substantial number of years. That mentality just doesn't cope with the kind of thing we have right now which is a four or five year period of an enormous economic cost disparity between places where there is cheap generation and other places where those people can use it."

A third IOU also stated that FERC requirements (that accepted rates be on file prior to the sale of wholesale power) constitute a significant impediment to increased sales. Another impediment identified was the intertie access policy of the Bonneville Power Administration. "We would like to have access to markets other than simply through BPA into the Northwest." The respondent's efforts to obtain transmission rights into Arizona have also been thwarted, although the interview did not make clear why this has been the case. Finally, the respondent referenced the phenomenon whereby transactions between Arizona and California are limited by the possibility of cascading outages of those ties, stemming from foreseeable conditions on the WSCC grid.

A fourth IOU stated that the major obstacle hindering its increased sales of capacity is the nature of the transmission system in the West, where stability and voltage drop concerns are endemic due to the long line lengths and the distance of generating facilities from load centers. Given the configuration of its system, the respondent's excess capacity would have to be transmitted from 400 to 800 miles to the Southern California area or to the West Texas market; stability and voltage drop considerations limit such sales. Specifically, the respondent noted the limitations of the transfer path from the Four Corners area westward. Also noted was the difficulty in obtaining right of way for the construction of any new transmission facilities to bring power to those markets, given that the owners of the land transversed enjoy no direct benefit from the presence of the line which can be readily demonstrated. Furthermore, uncertainty of recovery is a problem. "We have that with the eastern interconnection project - the one we built from the Albuquerque area into Southwest Public Service. It's not in our ratebase. It is intended to deliver power back into New Mexico....Now we have this problem under contract where we're going to start purchasing at a certain time period. When we don't need it from a resource perspective, so now we're further at a position of uncertainty."

The respondent also stated that loop flow is taking capacity on the system which precludes it from making bulk energy deals or economy energy transactions. WSCC experiments to compensate those impacted by loop flow for lost opportunities have failed, in the opinion of the respondent.

A fifth IOU from California stated that uncertainty of recovery and the status of regulation in a rapidly changing environment pose particular problems for its increased purchase or sale of capacity and energy.

In regard to uncertainty of recovery, the respondent recounted its experience with the California Commission's treatment of its Southwest Power Link. This interconnection was completed in 1984, after a decision to build was made in 1981-1982. The original decision to build the interconnection, while based on straightforward engineering and economic analysis, was influenced the California Commission, which had asked the respondent to explore interconnection as an alternative to the construction of a nuclear generating facility. At the time the decision was made, it was anticipated that the line would carry capacity for the most part, and it was demonstrated that the cost over the life of the line rendered that alternative more preferable than generation construction.

With the unforeseen decrease in oil and gas prices, however, it has become less expensive to utilize on-system generation than to import power over the line. As a result, "in our last rate case the decision came out that the Southwest Power Link was going to be treated separately from all the other material in our rate base. It would be singled out for a balancing account treatment, and the PUC questioned whether the line would be cost effective to present customers or whether the conventional economics relied too heavily on all the benefits of the line throughout its life, as opposed to current customers....The balancing account that was established is for five years, and the intention of the balancing account is to look at all the costs associated with the line...and comparing those to our short-run avoided cost. The premise of the account is that as long as that is a positive number, then we put the whole line in the rate base. If it's anything else, that's a direct hit to the shareholder." At the time of the interview the respondent was not using the line for energy because of lowered self-generation costs, but the capacity payment is required to be made. "We're going to take a five year balancing account right when the effects of these contracts are the worst, just before they end, carve out a piece and then balance it against a combustion turbine based, oil and gas based avoided cost...The Commission has, in its wisdom, chosen to attack the line itself and its prudence on a hindsight basis."

The respondent stated more generally that "the biggest single obstacle to building transmission lines is regulation in transition....The Commission is trying to help with the BPA problems, trying to help the utilities crack into the free market, at the same time they're trying to protect current customers and trying to protect cogenerators and honor PURPA and I don't see how anyone could succeed at all three of those simultaneously. So regulation needn't be the problem but just right now regulation is the focal point of a lot of conflicting changes."

The respondent also mentioned the bottleneck constraining increased purchases or sales in the Four Corners area, pointing out that the Indians negotiate on the basis of marginal cost pricing and that the state of Arizona is not anxious to provide a transmission path from California to Four Corners when its own utilities have a surplus of capacity to sell. The intertie access policy of Bonneville Power Administration was also pointed out to be an impediment to increased sales/purchases.

The sixth IOU from WSCC stated succinctly that "the transmission system is limited and from the regulatory standpoint there's an uncertainty there of whether any benefits we create by conducting these transactions can be returned to our owners."

A cooperative operating in Utah stated that "we would like to sell in Arizona and California but there has not been capacity available on other utility's transmission lines and we don't have intersystem transmission....My opinion is that transmission limitations may be a problem from time to time, particularly in the short term. The total market available though has got to be what's answered first. Is there enough market in California to justify building another line? As long as they can get plenty of hydro surpluses from the Northwest and transmission capacity to get it to California, there won't be a market to justify another line from Utah."

The respondent also mentioned Utah Power and Light's alleged policy to prevent anyone else in the state from building transmission.

A municipal cooperative operating in Utah stated there to be two primary impediments to increased purchases/sales of capacity and energy: the refusal to wheel power by utilities owning transmission facilities, and wheeling pricing practices of utilities owning transmission facilities. In regard to the former, the respondent stated that it is Utah Power and Light's policy to preserve its market power through control of its transmission facilities. "We asked...[an executive of Utah Power and Light] if we could wheel through their system; he said, you have got to find someone to wheel to. We said OK. We went out and found some markets; he said, well, if you can get to them, we can get to them, so any market you find, is our market."

Regarding wheeling pricing practices, the respondent indicated that methodologies for establishing wheeling prices can be manipulated. "the main thing is what is and is not included. Even with rolled in rates now, all the way down in our area, 46 kV and above is all one rate. If you don't include interconnections in the whole entire system out there, you force that rate up. You can eliminate those transfer capabilities on that system. UP&L could be moving 800 MW through their system at any one time selling down to the Southwest. If they don't include the interconnections in their pricing, they don't bring that 800 MW with them also. So they take the small loads down into the area, 200-300 MW, basically over that same investment out there, and then cut you off at the interconnection....So rates dramatically go up, so we help pay for an investment that really gives them a lot of revenue." In addition to the impediment posed by rolled in rate cost methodologies, the respondent stated that "more of an impediment...is the fact that FERC just won't allow anything over a mill on wheeling charges after cost."

Another wheeling pricing practice to which the respondent objected was the "pancaking" of wheeling charges. "UP&L negotiated three separate wheeling agreements with us. So we bought in - by this time being short of power and the PSC ordered UP&L to get out of the wholesale business. We bought into the Hunter 2 plant --the co-ops and munis together. So the way UP&L handled this, they gave us a wheeling agreement for the Hunter power resources, one for the Bonanza project and another for the Inter-Mountain Power Project. They filed none of them with FERC. So we felt like we had no wheeling agreement at all under the classic sense of wheeling. When we started taking power out of the Hunter unit, that's when they filed with FERC - they filed only that agreement with FERC. Then when the Bonanza project went commercial, they filed that agreement with FERC. I don't think they filed the [Inter-Mountain Power Project]...agreement with FERC yet. And we are anticipating taking power out of that project now. Our big concern in the methodology is that we get pancaked with three separate wheeling agreements. Those wheeling agreements were onerous. They were ratchet oriented - they were pancaked. We could have shipped power in one hour of 10 MW from Intermountain Power Project to one of our members...in the

next hour if we could have shipped from the Hunter system...and canceled out Intermountain of 10 MW, they would have charged us another ratchet - under the same FERC rates and the same for Bonanza. That is what we could have in three hours - we could have incurred a yearly ratchet for 30 MW and yet only move 10 MW of power."
One federal power authority stated that its increased sales are currently limited by the capacity of its interties, but that construction would eliminate that limitation in the next few years. Currently, loop flow problems load the interties in the Spring, when there is heavy runoff, and the ability to sell up to the full capacity of the intertie with California is limited, because part of the power on the intertie is loop flow.

The other federal power authority stated only that "we have faced some regulatory objections on the purchase or sale arrangement and one of them was when we were trying to move power from North Dakota to California, there were some people in between there that thought we shouldn't be buying it from North Dakota, the regulatory agencies, and we did into some opposition there on that particular thing."

A state power authority stated that heavy firm schedules from generating sources in Arizona and New Mexico limit its increased sales of capacity and energy. It noted that schedules from the Four Corners area are constrained for the same reasons. "Loop flow has had a significant impact on energy deliveries west of Arizona." The respondent also stated that there are no direct regulatory barriers preventing it from utilizing transmission for purchases or sales.

Increased sales/purchases are limited from the perspective of a municipal utility in WSCC by the size of the Pacific Intertie going northward. Other constraints are a provision in the city charter requiring that the respondent cannot sell energy to other utilities unless it is surplus to the need of the municipality. "That pretty well precludes us from entering in the long term sales contract." Loop flow out of the Pacific Northwest and out of Arizona and New Mexico was also mentioned as a significant barrier. "When other interregional sales are going on, that loop flow can decrease our transfer capability anywhere from 200 to 600 MW. When you look at a 600 MW sale, such as between Southern California Edison and ourselves, that's a big financial impact. The municipal utility also stated that its market with Canada is "somewhat blocked because of the intertie access policy of BPA. We feel our accessibility to long term contracts for economy power is severely impacted there."

Another impediment to its increased sales is a provision by which it must abide, requiring a 60-day callback provision which must be included in any contracts to sell. The provision requires that the respondent would be able to cancel the contract if the Northwest were experiencing any shortfalls in meeting its own energy and demand requirements. "That's been a real problem in the negotiations with the long term sales to the California utilities."